Final Report:

Wind Integration Study for Public Service Company of Colorado

Prepared for

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Technical Review Committee

The following individuals comprised a technical review committee (TRC) for this project. The TRC was kept apprised of the approach, methodology, and assumptions for the analysis described in this report, and provided valuable comments, suggestions, and guidance at several critical junctures from project commencement to conclusion.

PSCO Staff

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Jeff Pavlovic

Dana Echter

Bill Grant

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Michael Milligan	National Renewable Energy Laboratory
Ed DeMeo	Wind consultant
Matt Schuerger	Wind consultant
Brendan Kirby	Oak Ridge National Laboratory
Charlie Smith	Utility Wind Integration Group
Eric Hirst	Wind consultant
P.B. Schechter	Office of Consumer Counsel
John Nielson	Western Resource Advocates
Bob Zavadil	EnerNex Corporation
Mark Ahlstrom	WindLogics

Project Team

Xcel Energy retained EnerNex Corporation of Knoxville, Tennessee to assist with various technical aspects of wind integration issues for the PSCO system.

EnerNex Corporation is an electric power engineering and consulting firm specializing in the development and application of new electric power technologies. EnerNex provides engineering services, consulting, and software development and customization for energy producers, distributors, users, and research organizations. The company has substantial expertise with a broad range of technical issues related to wind generation, from turbine electrical design to control area operations and generation scheduling.

As a subcontractor to EnerNex, WindLogics of St. Paul, Minnesota provided meteorological expertise for the development and characterization of the wind energy resource in and around the PSCO service territory. Based in St. Paul Minnesota, WindLogics is a leader in advanced wind resource analysis, long-term wind variability and weather forecasting services. Using decades of weather data and advanced computer modeling techniques, WindLogics services help wind project developers, owner/operators, financiers and utilities reduce their financial risk and maximize their return through a better understanding of the wind. As part of the EnerNex team for assessment of wind integration costs and impacts, WindLogics provides expertise on wind modeling and forecasting issues which are both critical to the project results.

EnerNex and WindLogics are engaged in wind integration studies for a large number of clients across the U.S. In 2003, they were selected to conduct an assessment of 1500 MW in the Xcel-NSP control area in Minnesota. The approach and methods devised for that groundbreaking effort have been continually extended and augmented for a number of wind integration studies since that time, including the one reported here.

Executive Summary

Background

In 2004, Xcel Energy took the initiative in assessing technical and economic impacts of adding significant wind generation to its electric supply portfolio. The project reported here was devised to address several of the specific questions and directives of the Order and Stipulation for Docket No. 04A-325E, highlighted below in blue text.

Xcel-PSCO Requirements per Order and Stipulation for Docket No. 04A-325E:

[1] Estimate the ancillary service costs of 720 MW (~220 MW existing + 500 MW new RFP) of nameplate wind based on its 2007 peak demand, which peak demand is projected to be 7,148 MW, or the best available peak demand forecast at the commencement of the study (~10% penetration).

[2] The ancillary cost estimate should provide an estimate of all PSCo's generating units' (owned and/or controlled under tolling agreements) cost factors – including regulation, load following, and unit commitment (including start up costs and ramp rates).

[3] Estimate the ancillary service costs of a quantity of nameplate wind at 15% penetration based on its 2007 peak demand (or the best available peak demand forecast at the commencement of the study).

[4] Perform power flow and stability analysis, using 2007 power flow cases, of the portfolio of resources selected in response to the Renewable RFP. To the extent such analysis identifies problems with system stability, PSCo will recommend appropriate solutions.

[5] Develop written operating procedures and practices to maintain compliance with NERC and WECC.

[6] Determine whether ancillary costs vary by geographic region within the state (e.g Northeast vs. Southeast corners) and how the size of a wind facility impacts ancillary costs.

[7] Determine whether ancillary costs remain nearly the same for different sized facilities within certain ranges. The Commission will not specify the range, but instead instructs PSCo to examine the data to determine if it is appropriate to assume different ancillary costs depending upon size and geographic region, instead of a system-wide figure.

[8] Goal – ability to determine ancillary costs on a project-by-project basis for accurate comparison of projects in future RFPs and future LCP dockets.

[9] The study should analyze the effect of contracted wind bidder projects on PSCo's system, because ancillary costs may vary significantly based on wind penetration level, geographic location, and diversity of wind resources, and these factors can not be fully considered until Renewable RFP projects are under contract.

[10] Include one full year's worth of data from the Lamar wind project.

[11] Keep Commission staff informed of study progress and invite Staff to participate in technical review meetings.

[12] Complete all studies, analysis, and operating procedures and practices by April 1, 2006 (although this deadline may be extended with Commission approval).

The study reported here involves data, practices, and procedure from the non-regulated subsidiary of Xcel Energy. Items [4] and [5] involve analysis of the PSCO transmission network and relate to matters which fall under the open-access provisions of the FERC rules. They are being addressed in a separate report to the Commission.

Wind energy differs from conventional sources of electric generation in that its fuel supply can be highly variable and difficult to predict with high accuracy more than a few minutes to hours forward. While the energy delivered over an extended time frame - a year or the life of the facility - might be quite predictable, significant errors are likely when forecasting for specific hours even one day ahead.

Electric utility companies use sophisticated strategies and tools for deploying their generating resources in a way to serve the load reliably and at the lowest cost. Forecasts of demand over the next day to several days are the starting point for optimization processes that determine which resources should be committed to operation, and how they should be scheduled to serve that forecast load. The control and reliability needs of the system, along with limitations of the generating units themselves, constrain this optimization problem.

The variability and uncertainty of wind generation can add complication to this problem in various ways:

- Short-term variations in wind generation (minutes to tens of minutes) can necessitate the reservation of additional generating capacity to compensate for excesses or deficiencies in the supply as the system load varies. In general, this reserved capacity cannot be used to serve load.
- Wind generation also varies in accordance with meteorological patterns. These patterns usually do not align with the daily load patterns. Wind plants production may be low during the late afternoon when daily load is at its highest, or may be high during the overnight hours when the load is near daily minimums and the value of energy is the lowest.
- Errors in wind generation forecasts can increase the overall uncertainty for unit commitment and scheduling. Since the plan is optimized for forecast data, actual load and wind generation that significantly depart from forecasts will cause the plan to be less then optimal, implying that the cost to serve the load will be higher.

The objective of the study was to assess the costs that would be incurred by PSCO for taking delivery of the amounts of wind generation specified in the order and stipulation. The study consisted of the following major elements:

- Defining and developing a chronological representation of wind generation deployed throughout the eastern part of Colorado
- Determining how wind generation would affect the real-time control of the PSCO system, and what additional reserve capacity would be needed to maintain control performance at acceptable levels
- Calculating the differential in production cost that would be incurred in the day-ahead unit commitment and scheduling due to the variability and uncertainty of wind generation
- Assessing impacts of wind generation variability and uncertainty on the day-ahead procurement of natural gas for electric generation

Developing the Wind Generation Model

A chronological representation of wind energy production is essential for the methodology in this study. This data needs to accurately portray the following characteristics:

- The effect of spatial diversity within large wind plants, where the faster fluctuations in production from individual turbines are relatively uncorrelated, leading to much smaller normalized variations in the output of the entire plant;
- The effect of geographic diversity between large wind plants located miles to hundreds of miles apart. The effect is similar to spatial diversity, but at larger time increments;
- Correlation in production between geographically-separated wind plants since the fuel source is driven by a common meteorology. Large weather systems, for example, will affect all plants in the region, albeit not simultaneously.
- Effects of topography, where terrain features can enhance the wind resource potential by steering or funneling near-surface winds.

Also, as mentioned previously, correlation between wind generation and load may be an important factor to capture. Meteorological conditions that contribute significantly to peak load hours and days may also favor a certain wind regime.

The challenges associated with developing a data set with attributes as described above are significant. For this study, time-domain simulation of the meteorology over the entire region using one of the physics-based atmospheric models was used to “re-create” the weather for historical years. From this simulation model, wind speed data at hub height for commercial wind turbines was extracted at ten-minute intervals for 50 locations throughout the eastern portion of the state (Figure 1). Locations for these extraction points were selected based on known wind generation project activity or interest.

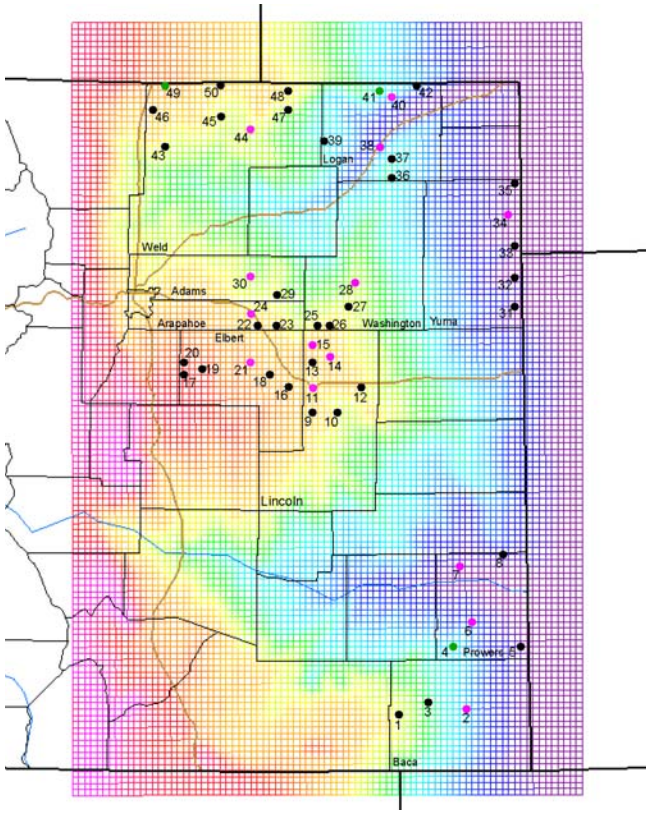

Figure 1: Placement of "proxy" towers at which hub-height wind speed data is to be saved from the meteorological simulations. (Background colors on map indicate elevation)

The PUC Order specifies the study of two levels of wind generation:

- 10% "penetration" (the ratio of installed wind generation capacity to projected hourly peak load for the 2007 study year). For the PSCO system, this level corresponds to 722 MW of installed capacity.
- 15% penetration, or 1038 MW

Further, as the planned wind generation approaches the 15% level, PSCO is to evaluate costs associated with integration of 20% wind penetration or 1444 MW. This 20% wind penetration study will be used to inform the 2007 Least Cost Resource Plan.

To create each scenario, proxy towers were specified to represent a small amount (30 MW) of wind generation. Enough towers were selected to achieve the desired amount of wind generation capacity. Selections were based on indicated project interest at the time. Table 1 documents the wind projects and installed capacity assumed for the 10% scenario. The location of the new projects is shown graphically in Figure 2.

Table 1: Phase I 10% Penetration Scenario for Xcel-PSCo Wind Integration Study

Project	Capacity	Rating for Study
Colorado Green	162 MW	162 MW
Peetz	30 MW	30 MW
Ponnequin	30 MW	30 MW
New Project 1	130 MW	165 MW
New Project 2	199 MW	240 MW
New Project 3	69 MW	95 MW
Total	**620 MW**	**722 MW**

The wind generation scenario for 15% penetration or 1038 MW was developed by adding proxy towers and projects to the 10% scenario. Figure 3 illustrates both scenarios.

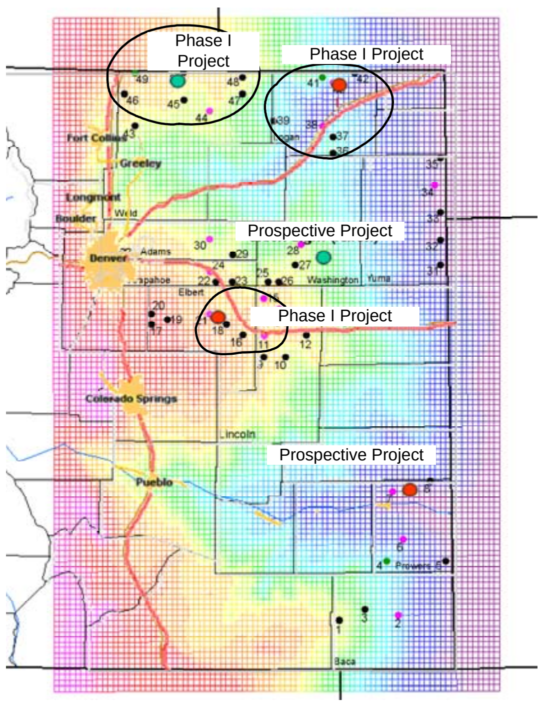

Figure 2: Proposed wind plant additions for Phase I scenario.

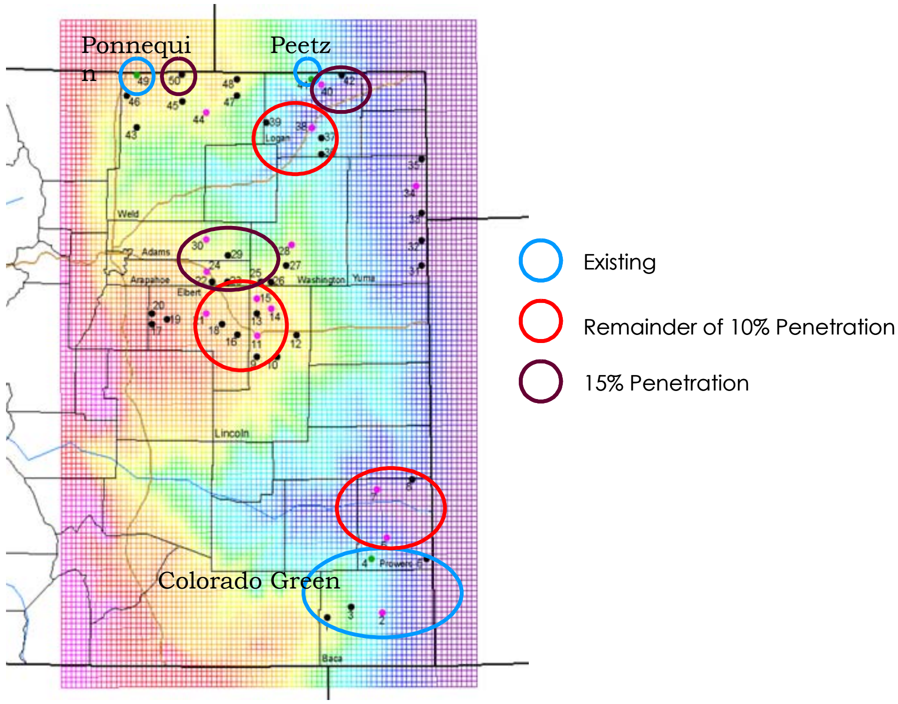

Figure 3: Final assignment of proxy towers by scenario.

Wind speed data from the simulation model corresponding to the proxy towers for each scenario was converted to wind power by applying a typical turbine power curve. Measurement data from the Peetz wind generation facility was used as guidance in this process. A single wind speed measurement from the model represents the average conditions across a four square kilometer grid. In the wind generation model, it is assumed that there are 30 MW of wind generation in each grid, or about 15 commercial turbines. Obviously, the single wind speed value cannot completely represent what is happening at each individual turbine, so applying a simple power curve can lead to significant differences between the model and reality. Figure 4 clearly shows this difference.

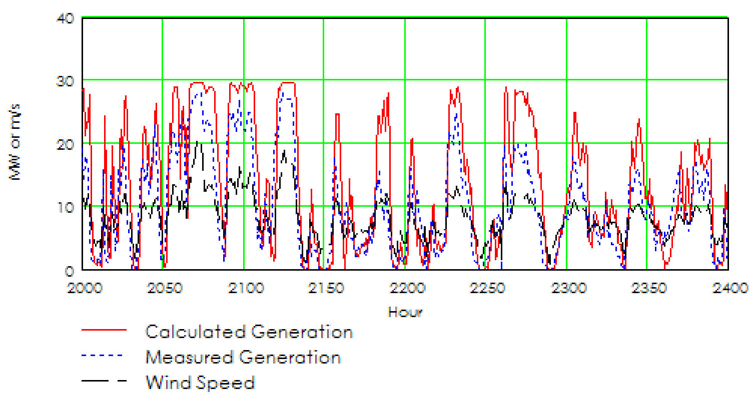

Figure 4: Calculated vs. measured wind generation using simple power curve.

An empirical adjustment was found by analyzing the Peetz measurement data that, when applied to the wind speed data from the model, leads to a much improved correspondence between the calculated and measured data (Figure 5). This adjustment was used for all calculations of wind power production time series in the project.

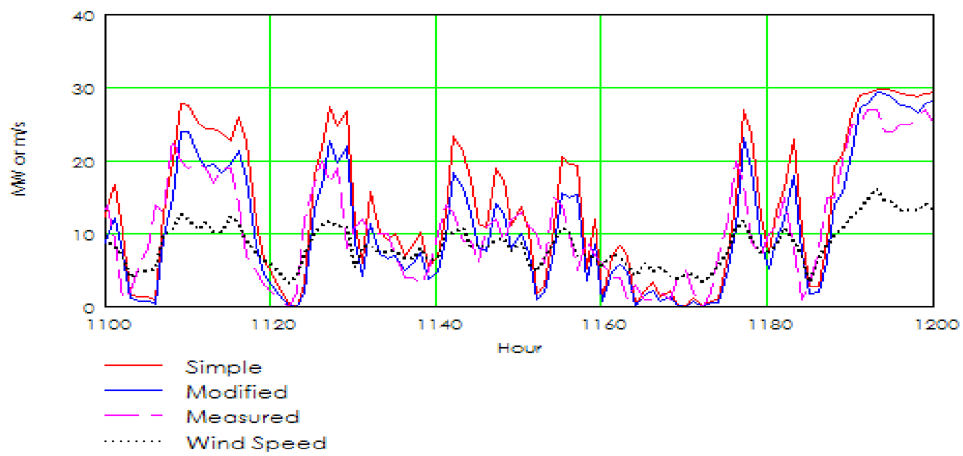

Figure 5: Comparison wind generation production profiles using simple model and empirical adjustment from Peetz measurement data..

Wind Generation Impacts on Power System Operations

Electric energy production from a large wind generation facility over a period of time – months, years, or the life of the project – can be estimated accurately enough to secure financing for the large amount of capital to construct the facility. Over shorter time frames, however, production is less predictable. One of the most significant barriers to further development of wind generation in the U.S. stems from the fact that the processes and procedures for the design, planning, and operating of large interconnected utility systems are necessarily biased toward resource capacity – the rate of energy transfer to the grid, not the amount delivered over a longer period of time - to insure the adequacy, reliability, and security of the electric supply for all end-users. Integrating large amounts of wind energy into the larger portfolio of electric generation resources requires some special considerations on the part of those charged with operating the electric system. Substantial amounts of wind generation in a utility system can increase the demand for the various non-revenue-generating actions called "ancillary services". The ability of and cost to the control area to provide the required level of these services for successful integration depends on the makeup of its generating fleet, agreements with neighboring control areas, or the existence of competitive markets for such services. While the various conventional electric generating technologies are able to provide some level of integration services, certain technologies such as combustion turbines may be more appropriate from the cost and capability perspective than large fossil or nuclear units.

There is a consensus in the wind and electric power industries that the variability and uncertainty of wind energy delivery increase the need for ancillary services from the control area operator. The question then becomes one of quantifying this integration cost.

Ancillary services are comprised of the practices and actions taken by operators of a control area within an interconnected electric power system to insure adequate system performance and reliability. The following list generally encompasses the range of technical aspects that must be considered for reliable operation of the system:

- Regulation – the process of maintaining system frequency by adjusting certain generating units in response to fast fluctuations in the total system load;
- Load following – ramping generation up (in the morning) or down (late in the day) in response to the daily load patterns;
- Frequency-responding spinning reserve – maintaining an adequate supply of generating capacity (usually on-line, synchronized to the grid) that is able to quickly respond to the loss of a major transmission network element or another generating unit;
- Supplemental Reserve – managing an additional back-up supply of generating capacity that can be brought on line relatively quickly to serve load in case of the unplanned loss of operating generation; and
- Voltage regulation and VAR dispatch – deploying devices capable of controlling reactive power[1] to manage voltages at all points in the network.

These ancillary services are critical for maintaining the reliability and security of the electric grid. For any foreseeable combination of equipment failures or mis-operation, operating generating units must remain synchronized to prevent cascading equipment outages and subsequent blackouts.

Much of the concern over how significant amounts of variable wind generation can be integrated into the operation of a control area stems from the inability to predict accurately what the generation level will be in the minutes, hours, or days ahead. The nature of control area operations in real-time or in planning for forward periods is such that better knowledge of what will happen correlates strongly to better strategies for managing the system. Much of this process is already based on predictions of uncertain quantities. Hour-by-hour forecasts of load for the next day or several days, for example, are critical inputs to the process of deploying electric generating units and scheduling their operation. While it is recognized that load forecasts for future periods can never be 100 percent accurate, they nonetheless are the foundation for all of the procedures and processes for operating the power system. Increasingly sophisticated load forecasting techniques and decades of experience in applying this information have done much to lessen the effects of the inherent uncertainty.

Impacts on the operation of the transmission grid and the control area relative to wind generation are dependent on the performance of the wind plants within that area as a whole, as well as on the characteristics of the aggregate system load and the generation fleet that serves it. Large wind generation facilities that are connected directly to the transmission grid employ large numbers of individual wind turbine generators.

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1 Electric machinery requires two components of current to operate: power producing current and magnetizing current. Power producing or working current is current that is converted by the equipment into work. The unit of measurement of active power is the Watt. Magnetizing current, also known as reactive current, is the current required to produce the flux necessary to the operation of electromagnetic devices. Without magnetizing current, energy could not flow through the core of a transformer or across the air gap of an induction motor. The unit of measurement of reactive power is the VAR. Management of reactive power is the primary mechanism for controlling voltage at points within the network. System operators dispatch various devices capable of producing reactive power, including generators, shunt capacitor banks, static VAR compensators, etc., to control voltages in response to continually varying customer demand.

Individual wind turbine generators that comprise a wind plant are usually spread out over a significant geographical expanse. This has the effect of exposing each turbine to a slightly different fuel supply. This spatial diversity has the beneficial effect of "smoothing out" some of the variations in electrical output. The benefits of spatial diversity are also apparent on larger geographical scales, as the combined output of multiple wind plants will be less variable than with each plant individually.

The system load itself exhibits some unpredictable variations, both within an hour and over the course of the day. Because system operators are concerned with the balance of net load to net generation in their control area, load and wind variations cannot be considered separately. The impact of uncorrelated variations in load and wind over time will be considerably less than the arithmetic sum of the individual variations. This aggregation effect is already a critical part of control area operations, as responding to or balancing the variations in individual system loads, rather than the aggregate, would be exorbitantly complicated and expensive, as well as non-productive.

Evaluation of Wind Generation Impacts on the PSCO System

Specific technical and economic impacts of the wind generation scenarios defined in the PUC Order were quantified for the PSCO system using the chronological wind production model described earlier. The technical analysis consisted of two primary components:

- Evaluation of impacts on real-time operations via mathematical and statistical analysis of the wind generation data from the model and PSCO load data from its measurement archives.
- Quantification of the effects of wind generation on production cost associated with unit commitment and scheduling.

Regulation Impacts

Power system operators must constantly balance supply with demand in the control area. Since load by itself exhibits variability on all time scales, some generation capacity must be deployed to respond to these changes, i.e. provide regulation. Figure 6 shows the variation of system load over a one hour period superimposed on an underlying load trend. The fast variations in system load must in general be compensated for by adjustments in generation. The difference between the instantaneous values (blue curve) and the load trend (red curve) is defined as the "regulation characteristic".

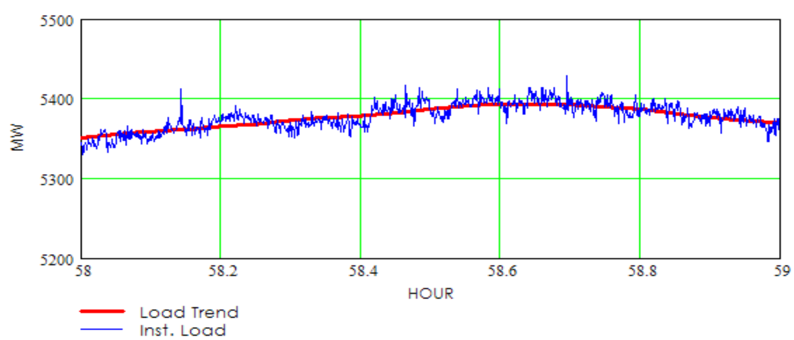


Figure 6: Instantaneous system load at 4 second resolution and load trend

One week of high-resolution load data from each season was extracted from PSCO EMS archives as the basis for the determination of the existing regulation characteristic of the system load. Analysis of this archived data lead to a fairly significant finding with respect to wind generation impact – A large portion of the existing regulation requirement for the PSCO system is attributable to a single arc furnace load. The upper plot in Figure 7 shows a single day of the PSCO load at a time resolution of four seconds. The load characteristic net of the existing wind generation is also shown. In the bottom plot in that figure, existing wind energy delivery (about 222 MW nameplate capacity) is plotted against the daily demand for the arc furnace.

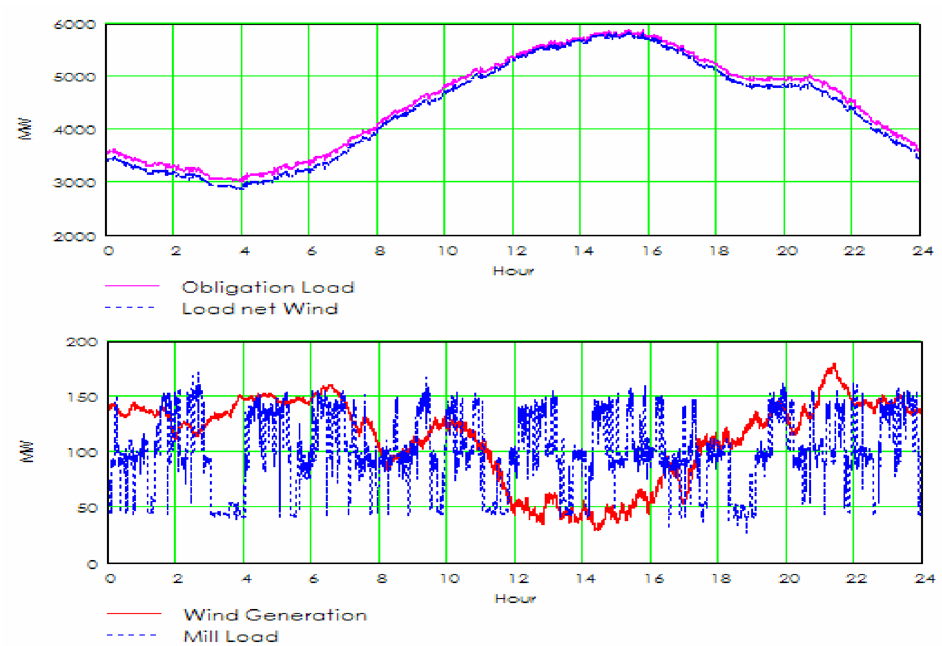


Figure 7: Top - High-resolution depiction of PSCO obligation load (with and without wind generation). Bottom – arc furnace load and wind energy production for same day.

Statistical analysis of the current load data shows that the standard deviation of the regulation characteristic averages 15.92 MW, with a few days either above or below this range. Given current operating practice, the amount of regulation capacity reserved to compensate for these deviations is about 60 MW, or 4 times the standard deviation of the regulation characteristic.

Adding the 222 MW of wind generation to the obligation load increases the average standard deviation of the regulation characteristic only slightly, from 15.92 MW to 16.02 MW, or about 100 kW.

Based on these findings, the effect of new wind generation on the fast-responding regulation reserves for the PSCO control areas is projected to be very modest. Calculations show that the estimate increase in regulation capacity for the addition of 722 MW of wind generation will be about 1.5 MW. At 15% penetration or 1038 MW, this incremental requirement increases to 2.5 MW.. Using a marginal capacity costing approach, the regulation cost around $0.05 for each MWH of wind energy delivered to the system.

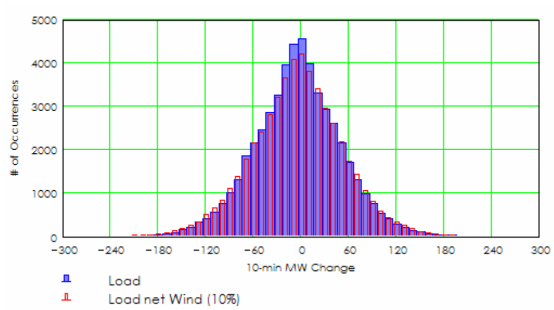
The analysis in this project says nothing about how the regulation burden should be allocated to the load, wind generation, or the arc furnace load, but instead simply determines how much total wind generation at the given penetration levels increases the requirement over that for the obligation load including the arc furnaces. Since regulation impacts are nonlinear, the first entity would be assigned a disproportionate share of the regulation burden in an incremental scheme2.

Load Following

PSCO operators must also insure that generation is available to compensate for the slower changes in control area demand (the "trend" from the plot above). Generating resources must be adjusted to follow the control area demand as it rises in the early part of the day and declines in the evening and overnight. Wind generation is obviously not linked to any diurnal pattern of the load, and may alter the requirements for moving generation over short-periods within an hour and over intervals of one to several hours.

Statistical analysis of PSCO archived load data (Figure 8) shows that 95% of the load changes over a ten-minute interval are less than +/- 117 MW. When wind generation corresponding to 10% of peak hourly load in 2007 is added to the control area, the 95% value for the ten minute deviations increases to 124 MW. At 15% wind generation, this grows to 131 MW.

The analysis which underlies these numbers is quite simple. Based on discussions with PSCO operators, these results were compared to an internal analysis of regulating reserve requirements based on data from the PI system (PSCO database for EMS archive data) and a more detailed (than the current study) mapping to actual PSCO operational practice. The results reached with this method agreed relatively well with those from this study.



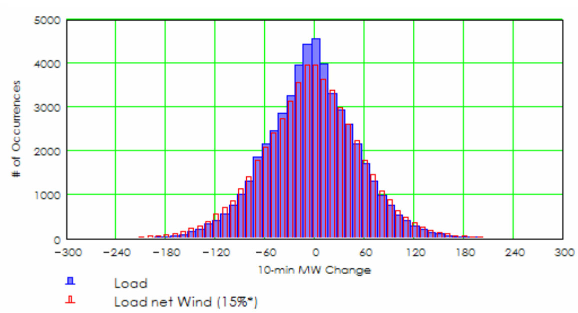


Figure 8: Deviations in control area demand at ten-minute intervals with and without wind generation.

In summary, the simple analysis of the wind and load data at ten minute intervals in this study provides insight into how wind generation may affect real-time control. Based on the analysis, the effects are likely much less than would be experienced should the arc furnace load go from two 50 MW furnaces to a single 100 MW furnace. Regarding the furnaces, however, there is actually some predictability that is used to assist real-time operators. If the furnace is off, for example, the operators know that it can only go on to the 50 or 100 MW level. Conversely, and perhaps more importantly, if the furnace is full on, the operators incorporate the fact that the furnace load can only decline suddenly. This information may influence decisions to deploy additional regulating resources.

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2 B. Kirby and E. Hirst, *Customer-Specific Metrics for The Regulation and Load-Following Ancillary Services*, , ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge TN, January, 2000

It is anticipated that the same level of comfort and adaptation with wind generation will be developed over some period of on the job training.

Unit Commitment and Scheduling

Wind generation integration cost is a function of the variability and uncertainty of energy delivery to the PSCO control area. Because wind generation can vary in an unfavorable pattern with respect to the system load, and can be predicted with only a certain degree of accuracy for forward periods for which optimum operating plans are constructed, additional cost can be incurred to serve the load not served by wind generation. The method used to calculate costs at the hourly level uses a series of comparative cases, and is designed to compare wind generation to a resource which does not possess those attributes that contribute to integration cost.

The analysis mimics the activities of PSCO generation schedulers and real time operators. An optimal plan is constructed based on hour-by-hour forecasts of the control area demand for the next day. Using this plan as a starting point, the day is simulated using actual rather than forecast control area demand.

With wind generation on the system, PSCO operators will use some type of next-day forecast of wind generation and load to construct the best plan for meeting the control area demand. Fuel for gas-fired generating units will also be purchased or "nominated" based on this plan. When the day arrives, both hourly load and wind generation will likely depart from the forecasts used to develop the optimal plan. The consequence is that actual operations over the day will likely be less than optimal (i.e. lowest cost) for the actual load and actual wind generation.

Integration cost in this study is defined as the difference between the actual production cost incurred to serve the net of actual load and actual wind generation and the production cost from the reference case, where wind is perfectly known and adds no variability to the control area, and where next-day load is the only uncertainty.

The method for determining the costs at the hourly level proceeds as follows:

1. Run the unit commitment program (ABB Couger) in "optimization" mode to develop a plan for serving the forecast load. Wind generation for the day is known perfectly, and is delivered in equal amounts each hour through the day.
    a. Save the unit commitment as the starting point for the next case.
    b. Determine the hourly gas requirements and shape into an 8 am to 8 am "reference nomination".
2. Using the unit commitment from 1), re-run the day with forecast load replaced by actual load. Do not allow the program to re-optimize, but allow it to re-dispatch available units to meet the actual load. Manually commit generation to meet load that cannot be served from the previous day commitment.
    a. Save the total production cost for the period and define it as the "reference production cost"
    b. Calculate the hourly deviation in gas requirements from the reference nomination. These deviations must be accommodated by injection or withdrawal operations with system storage.
3. Repeat Step 1) with a next-day hour-by-hour wind generation forecast in addition to the load forecast.
    a. Save the unit commitment as the starting point for the next case.

b. Determine the hourly gas requirements, shape into a flat "actual nomination"

4. Using the unit commitment from 3), re-run the day with forecast load and forecast wind generation replaced by actual load and actual wind generation. Do not allow the program to re-optimize. Re-dispatch available units and manually commit off-line units to meet the control area demand.

    a. Save the total production cost for the period and define it as the "actual production cost".

    b. Calculate the hourly gas deviations from the "actual nomination"

The above process is repeated for at least one year of wind and load data. Total integration cost on the electric production side is calculated by subtracting the production cost from Step 2) from that in Step 4).

Results from the hourly analysis using the method described above are shown in Table 2. An initial evaluation of the 20% penetration level was conducted, but these results gave rise to some significant questions concerning wind generation forecast accuracy, operational practice during periods of high wind generation and low load, and sensitivity of integration costs to assumptions and input data. Results for the 20% penetration case will be reported later.

Table 2: Summary of Electric Production Cost Impacts

Wind Penetration	Electric Production Cost Differential
10%	$2.25
15%	$3.32

Impacts on Natural Gas Procurement and Supply

Fuel for the natural gas-fired generation in the PSCO supply portfolio is acquired on a day-ahead basis. These nominations are made by early morning of the previous day based on forecasts of control area load and plans for commitment and utilization of gas-fired generation.

Of concern here is the additional day-ahead uncertainty attributable to significant amounts of wind energy in the generation mix. Since storage is limited, gas shortages would necessitate very expensive emergency power purchases, and errors in the other direction would lead to wasting of fuel.

Gas utilization was tracked in the hourly analysis. By processing the results of the sub-cases in the methodology, it was possible to calculate how wind generation variability and uncertainty would impact the gas supply system. The cost of these impacts was calculated using an incremental storage methodology. The results of these calculations are shown in Table 3. The benefits of the incremental gas storage as a hedge against price fluctuations was credited back to wind generation, so that the last line of the table corresponds to the net of gas supply impacts attributed to wind generation.

Table 3: Estimated Financial Impacts on PSCO Gas Supply due to Wind Generation Variability and Uncertainty.

Wind Penetration	10%	15%
$/ MWH Gas Impact No Storage Benefits	**$2.17**	**$2.52**
$ / MWH Gas Impact With Storage Benefits	**$1.26**	**$1.45**

Hourly Results for Phase I

Total integration costs for the two scenarios are shown in Table 4.

Table 4: Summary of Integration Costs for Phase I Analysis

Wind Penetration	Electric Production Cost Impact	Gas Supply System Impact	Total
10%	**$2.25**	**$1.26**	**$3.51/MWH**
15%	**$3.32**	**$1.45**	**$4.77/MWH**

Phase II Analysis

A follow-on effort, designated as the "Phase II" of the study, was defined to address certain items from the Order and Stipulation not covered by the initial analysis.

One of these items was to address regional variations in the wind resource, and how they might influence integration costs for various wind development scenarios.

Wind generation in PSCO territory is allocated to one of four regions within the eastern half of the state:

1. North
2. East
3. Central
4. South (actually southeast)

For each region, variability statistics were computed for a collection of six proxy towers assigned to that region. That number was chosen as the sample size since there were only that many proxy towers located in the East region. It was assumed that a single 1.5 MW turbine was installed at each proxy tower location in the sample. Hourly generation was computed for a three years sample of hourly data.

Change in wind generation from hour to hour was chosen as the metric to represent variability. For each region, an average hourly wind generation was calculated from the individual turbine/proxy tower locations. The standard deviation of the hour-to-hour differences was then computed.

Differences in the hour-by-hour variations between regions (Table 5) do not appear to be significant based on this relatively perfunctory analysis.

The current understanding of drivers for wind integration costs makes differentiation by location somewhat difficult. It is recognized that greater geographic diversity reduces aggregate wind generation variability, which would tend to reduce integration costs. Some small control areas in the U.S. are experiencing significant operational challenges related to single large wind generation facilities. If the same capacity had been distributed to multiple geographic locations, the effects as seen from the control room would likely be lessened. However, the wind and power industries have not yet accrued an adequate quantitative understanding to support such a differentiation.

It should also be noted that transmission issues were not explicitly considered in this study. Transmission issues are likely as much or more of a factor in locational issues for wind generation development than differences in production variability by region.

Table 5: Standard Deviation of Hourly Variability by Region

Region	Hour Variability (% of rated)
North	10.9%
East	11.5%
Central	12.1%
Southeast	11.4%

While the variability of wind resource does not appear to vary much between regions, a wind generation scenario where development was concentrated in a single region (relative to the assumptions used in Phase I) could exhibit much more variability in the aggregate.

To assess how the integration costs would be affected by this type of development, a new scenario was created. Generation in the Central region was maximized since it contained the largest number of proxy towers. The increased capacity was drawn from the North and Southeast.

The wind model described in the previous section was inserted into the identical frame work for the 15% penetration case from Phase I. Integration cost from the hourly analysis with this wind model is slightly higher ($3.92/MWH vs. $3.32/MWH) than the Phase I case for this penetration level. Since the only difference between the cases is the wind generation model, it is logical to assume that this difference can be attributed to increased variability.

Project Summary and Conclusions

The results of the analysis show that:

- The costs attributable to the integration of wind generation into the PSCO system range from $3.51/MWH of delivered wind energy at installed capacity level equivalent to 10% of the projected peak hourly load in 2007 up to $4.77/MWH at 15%.
- Uncertainty of next-day wind energy delivery has a negative impact on the nomination of natural gas deliveries for residential/industrial use and as fuel for gas-fired electric generating facilities. A methodology based on incremental storage requirements for accommodating this additional uncertainty was developed. Results show the gas system cost of integrating wind generation range from $1.26/MWH of wind generation at 10% penetration to around $1.45/MWH at the 15% level.
- The costs for additional regulation and real-time control resources are quite small at the 10% and 15% penetration levels. Costs computed from the results

of statistical analysis of wind generation and system load data are about $0.05/MWH of delivered wind energy.

- Variability of the aggregate wind generation, which is what is observed either directly or indirectly from the PSCO system control center, is strongly influenced by geographic diversity of wind project development. From the baseline wind speed and wind generation data synthesized for this project, wind generation variability does not exhibit a regional bias, i.e. variability is not influenced by a project's location within the state.
- While there are unique regional challenges for wind generation forecasting, there is no evidence at this time to conclude that day-ahead forecasting would be more difficult (and therefore contain larger errors) in any one region relative to the others.

While the methodology used to derive the quantitative results is thought to be quite sound and well founded, a number of assumptions and compromises are necessary to process the volume of data necessary to estimate annual costs. The project team believes that the net effect of these is to make the results somewhat conservative in that they would tend to overstate integration costs over what might be achieved with experienced system operators and power traders. Decisions available to the real-time "operators" conducting the analysis were purposely limited to insure some consistency and repeatability as the various cases were executed. The same can be said for day-ahead power marketing and scheduling, where purchase and sale opportunities were simplified to allow modeling in the analytical tool selected for the analysis. In reality, both groups would develop, on the basis of ever-increasing experience with wind generation, strategies that would tend to reduce the cost of managing wind generation over time.

The wind generation development scenarios constructed as the basis for this study are proving to be somewhat different than the unfolding reality in the PSCO service territory. This naturally leads to questions regarding the applicability of the results and conclusions developed here to PSCO going forward. From the results and experience gained in the project, a couple of points can be made on this topic:

- While the computed integration costs do exhibit sensitivity to input data (especially the wind generation model), the differences are certainly relatively small and in the range of variation that could be expected by altering some other study assumptions such as the assumed "rules" for real-time dispatch or the introduction of intra-day re-optimization base on short-term wind generation and load forecasts.
- The integration costs computed here are in relative agreement with those obtained for similar wind generation penetration levels in other utility systems or control areas.
- Integration "costs" may be only one side of the equation for wind energy. Recent studies are showing that long-term fixed priced wind energy contracts offer the fuel cost stability normally associated with coal generation but without the potential exposure to carbon penalties[3,4]. In addition, fixed price wind contracts may be an option to hedging the natural gas used in a utilities' portfolio.

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[3] Bolinger, M. "Hedging Future Gas Price Risk with Wind Power" presented at the Annual Meeting of the Utility Wind Integration Group, Arlington, Virginia, April 2006

[4] Clemmer, S. "Hedging Future Carbon Risk with Wind Power" presented at the Annual Meeting of the Utility wind Integration Group, Arlington, Virginia, April 2--6

- Transmission issues were considered only peripherally in the analysis. For example, PSCO obligation load and all generating units were considered to be connected to a single bus, and limitations were placed on purchases and sales to external areas in consideration of transmission capability. At the current time there are some transmission limitations that will affect the dispatch of certain PSCO resources in the same regions as significant wind generation.

All things considered, the project team believes that the integration costs calculated here represent reasonable estimates of what would be incurred by PSCO as a result of increasing wind generation in their system.

Introduction - Study Background

Public Service of Colorado ("PSCO"), a subsidiary of Xcel Energy, issued its 2003 Least Cost Resource ("LCP") to the Colorado Public Utilities Commission ("CPUC") on April 30, 2004. Part of PSCO's LCP included a competitive solicitation for new generation resources to meet the company's energy and capacity needs over a 10-year acquisition period. In its evaluation of alternative resources, PSCO analyzed a range of resource types including thermal, wind, demand-side management and others to determine the lowest cost resource mix. In 2004, as part of a settlement agreement between parties involved with the LCP, Xcel Energy took the initiated a Wind Integration/Ancillary Service cost study. The specifics from the Order and Stipulation for Docket No. 04A-325E are detailed below:

Xcel-PSCO Requirements per Order and Stipulation for Docket No. 04A-325E:

[1] Estimate the ancillary service costs of 720 MW (~220 MW existing + 500 MW new RFP) of nameplate wind based on its 2007 peak demand, which peak demand is projected to be 7,148 MW, or the best available peak demand forecast at the commencement of the study (~10% penetration).

[2] The ancillary cost estimate should provide an estimate of all PSCo's generating units' (owned and/or controlled under tolling agreements) cost factors – including regulation, load following, and unit commitment (including start up costs and ramp rates).

[3] Estimate the ancillary service costs of a quantity of nameplate wind at 15% penetration based on its 2007 peak demand (or the best available peak demand forecast at the commencement of the study).

[4] Perform power flow and stability analysis, using 2007 power flow cases, of the portfolio of resources selected in response to the Renewable RFP. To the extent such analysis identifies problems with system stability, PSCo will recommend appropriate solutions.

[5] Develop written operating procedures and practices to maintain compliance with NERC and WECC.

[6] Determine whether ancillary costs vary by geographic region within the state (e.g Northeast vs. Southeast corners) and how the size of a wind facility impacts ancillary costs.

[7] Determine whether ancillary costs remain nearly the same for different sized facilities within certain ranges. The Commission will not specify the range, but instead instructs PSCo to examine the data to determine if it is appropriate to assume different ancillary costs depending upon size and geographic region, instead of a system-wide figure.

[8] Goal – ability to determine ancillary costs on a project-by-project basis for accurate comparison of projects in future RFPs and future LCP dockets.

[9] The study should analyze the effect of contracted wind bidder projects on PSCo's system, because ancillary costs may vary significantly based on wind penetration level, geographic location, and diversity of wind resources, and these factors can not be fully considered until Renewable RFP projects are under contract.

[10] Include one full year's worth of data from the Lamar wind project.

[11] Keep Commission staff informed of study progress and invite Staff to participate in technical review meetings.

[12] Complete all studies, analysis, and operating procedures and practices by April 1, 2006 (although this deadline may be extended with Commission approval).

Resource Needs

The magnitude and timing of resource need for the PSCO system over the ten-year resource acquisition period is illustrated in Figure 9. This figure indicates a need for approximately 3,600 MW of resources in 2013 using a 17% reserve margin on the base demand forecast. This resource need is driven by a combination of;

- Forecasted load growth plus reserves (approx. 1,200 MW)
- Expiring purchase power contracts (approx. 2,400 MW)

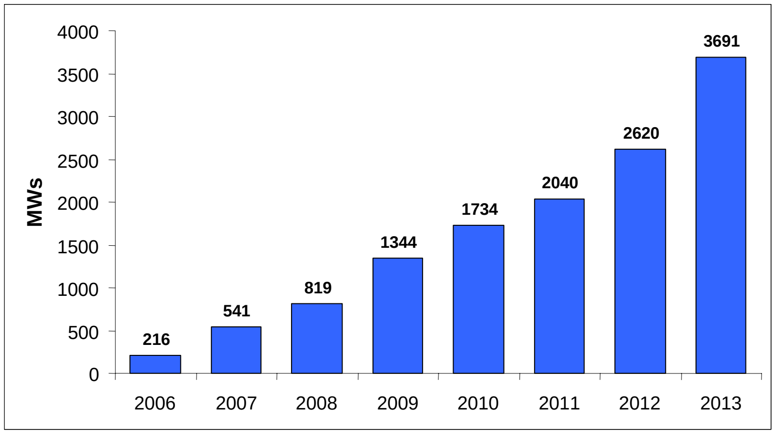

Figure 9: Project growth in energy needs for PSCO, 2006-2013.

PSCo Generation Supply Mix

In the past ten years, the Colorado Front Range economy has grown. With this economic growth has come an increasing demand for electric power. To meet this increase in electric demand the Company has been in an acquisition mode for new generation supplies and DSM reductions since approximately 1995.

The acquisition of additional resources during this time period has resulted in a significant change in the composition of the Company's generation supply mix. The change in the PSCO resource mix from 1995 to 2004 is illustrated graphically in Figure 10. This figure shows the that in 1995 the PSCO system was composed of 77% baseload coal (including purchases from other utilities), 13% Qualifying Facilities (QFs), and the remaining 10% a mixture of wind, hydro and gas.

As a result of purchase power contract terminations and contracted capacity reductions, from 1995 to 2004, the system has seen a reduction of approximately 400 MW of baseload utility purchased capacity. In addition, in 2003, a 90 MW reduction in coal-fired baseload capacity occurred with the retirement of the Company-owned Arapahoe Units 1 and 2.

This reduction in baseload resource capacity coupled with approximately 2,500 MW of effective peak demand growth since 1995 required adding a significant amount of new generation supply capacity over the last ten years. Approximately 3,000 MW of new gas-fired generation capacity was added to the PSCO system to meet a most of this need for additional capacity supply.

By the summer of 2004, the Company's resource capacity mix, as shown in Figure 10, will be comprised of approximately 48% gas, 44% coal, 4% hydro, and 1% wind. Several factors contribute to the considerable change in resource mix including the reduction in baseload capacity, the increase of peak demand, and acquisition of mostly gas-fired resources to replace lost capacity and to supply continued load growth.

Existing (purchased and owned) wind facilities within the eastern half of Colorado are highlighted in Figure 11.

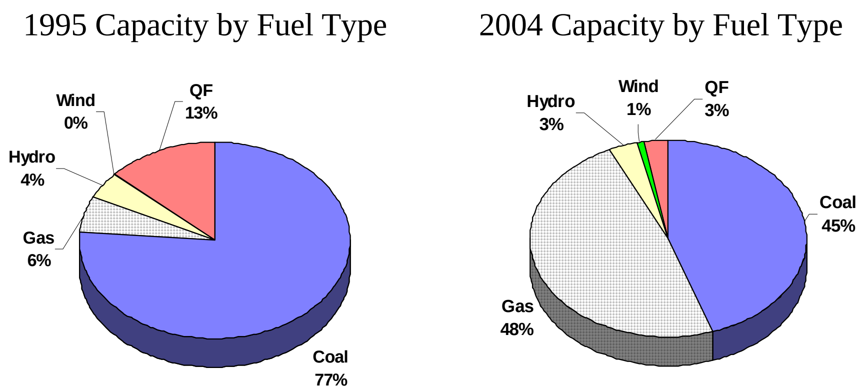

Figure 10: PSCO resource mix – 1995 and 2004

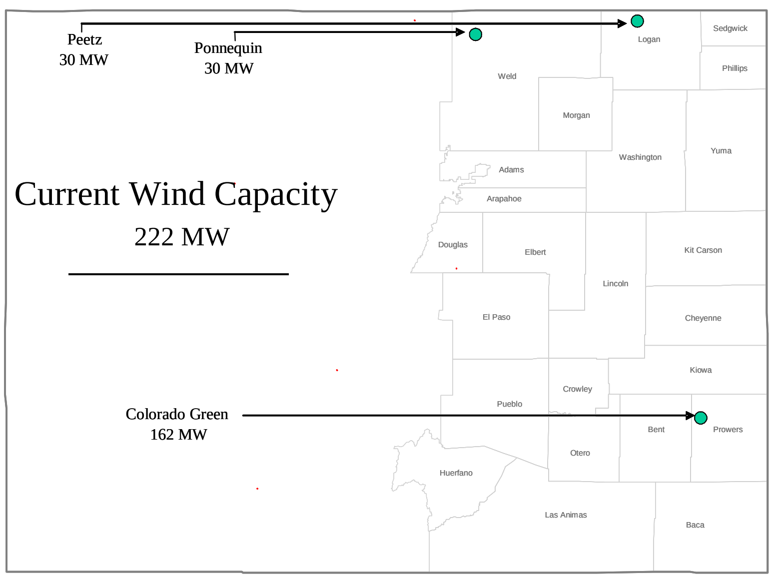

Figure 11: Existing wind generation facilities in eastern Colorado.

The National Renewable Energy Laboratory's wind density map in Figure 12 details the superior wind development capability available to PSCO.

Colorado has severe transmission import constraints from the north, west, and south. To the east, Colorado is adjacent to the Eastern Interconnect. Due to these transmission constraints, PSCO must rely heavily on its existing resources to meet not only its load, but contingency planning, reserve sharing arrangements, and ancillary services for intermittent resources. Note, the addition of the 210 MW High Voltage Direct Current ("HVDC") transmission line (a.k.a., the Lamar Tie-Line) is not shown on this map in Figure 13.

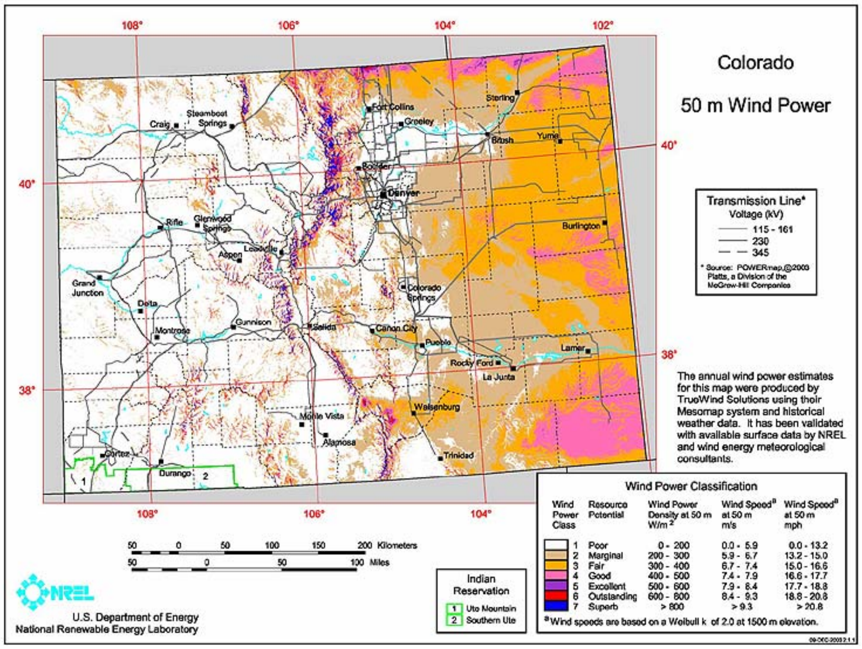

Figure 12: Wind resource potential in Colorado (from NREL)

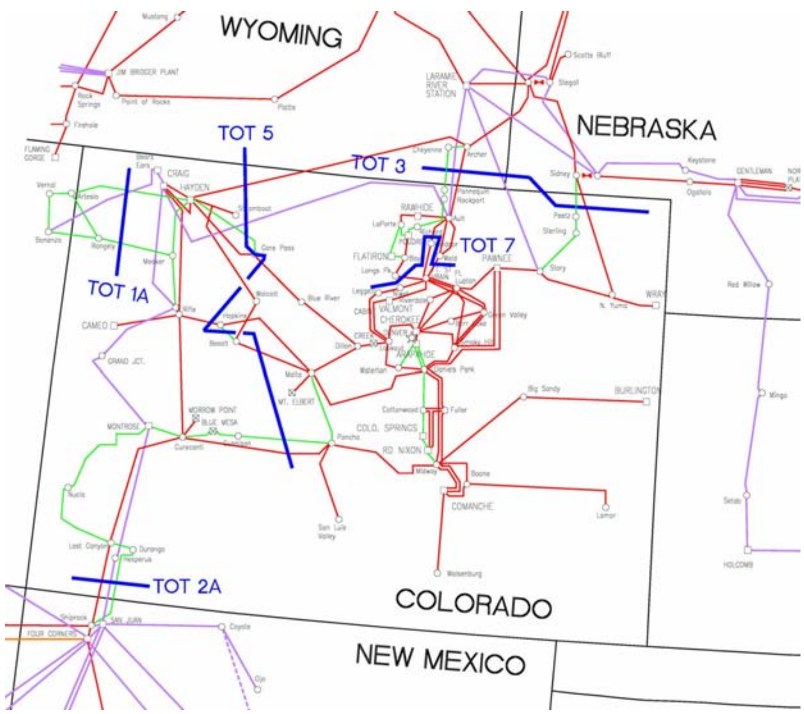

Figure 13: Transmission constraints in Colorado.

Wind Integration Cost Primer

Electric energy production from a large wind generation facility over a period of time – months, years, or the life of the project – can be estimated accurately enough to secure financing for the large amount of capital to construct the facility. Over shorter time frames, however, production is less predictable. One of the most significant barriers to further development of wind generation in the U.S. stems from the fact that the processes and procedures for the design, planning, and operating of large interconnected utility systems, are necessarily biased toward resource capacity – the rate of energy transfer to the grid, not the amount delivered over a longer period of time - to insure the adequacy, reliability, and security of the electric supply for all end-users. Integrating large amounts of wind energy into the larger portfolio of electric generation resources requires some special considerations on the part of those charged with operating the electric system. Substantial amounts of wind generation in a utility system can increase the demand for the various non-revenue-generating actions that are the subject of the next section. The ability of and cost to the control area to provide the required level of these services for successful integration depends on the makeup of its generating fleet, agreements with neighboring control areas, or the existence of competitive markets for such services. While the various conventional electric generating technologies are able to provide some level of integration services, certain technologies such as combustion turbines operating in simple combined cycles may be more appropriate from the cost and capability perspective.

Ancillary Services for Insuring Power System Reliability and Security

Interconnected power systems are large and extremely complex machines. The mechanisms responsible for their control must continually adjust the supply of electric energy to meet the combined and ever-changing electric demand of the system users. There are a host of constraints and objectives that govern how this is done. In total, however, those actions must result in:

- Keeping voltage at each node (a point where two or more system elements – lines, transformers, loads, generators, etc. – connect) of the system within prescribed limits;
- Regulating the frequency (the steady electrical speed at which all generators in the system are rotating) of the system to keep all generating units in synchronism; and
- Maintaining the system in a state where it is able to withstand and recover from unplanned failures or losses of major elements.

"Ancillary services" is the term generally used to describe the actions and functions related to the operation of a control area within an interconnected electric power system necessary for maintaining performance and reliability. While there is no universal agreement on the number or specific definition of these services, the following list generally encompasses the range of technical aspects that must be considered for reliable operation of the system:

- Regulation – the process of maintaining system frequency by adjusting certain generating units in response to fast fluctuations in the total system load;
- Load following – ramping generation up (in the morning) or down (late in the day) in response to the daily load patterns;

- Frequency-responding spinning reserve – maintaining an adequate supply of generating capacity (usually on-line, synchronized to the grid) that is able to quickly respond to the loss of a major transmission network element or another generating unit;
- Supplemental Reserve – managing an additional back-up supply of generating capacity that can be brought on line relatively quickly to serve load in case of the unplanned loss of operating generation; and
- Voltage regulation and VAR dispatch – deploying devices capable of controlling reactive power5 to manage voltages at all points in the network.

These ancillary services are critical for maintaining the reliability and security of the electric grid. For any foreseeable combination of equipment failures or mis-operation, operating generating units must remain synchronized to prevent cascading equipment outages and subsequent blackouts.

Historically, a single entity had complete autonomy over operation of the generation and transmission assets in a service territory and the responsibility for operating them in a manner to achieve high reliability at the lowest cost. Ancillary services are tools for achieving these goals. With the deregulation of the wholesale electric power industry, the institutional responsibility for certain of these functions in some regions of the country is being been reallocated. Their technical reality, however, has not been changed in that they must still be provided somehow, some way, by someone.

The implementation of competitive markets for ancillary services is in its relative infancy and is not uniform across the country. The emergence of market competition, in any form, has changed many of the procedures and processes for power system control and operation. Bidding supply into markets for the next hour or next day has replaced the historical top-down decision making process used to commit and schedule generating units. Some bi-lateral agreements between neighboring utilities for exchanging economic energy on short notices have been supplanted by spot markets. Planning for the appropriate level of reserve supply is now in some locales the function of capacity markets.

Ancillary Service Requirements for Wind Generation

Much of the concern over how significant amounts of variable wind generation can be integrated into the operation of a control area stems from the inability to predict accurately what the generation level will be in the minutes, hours, or days ahead. The nature of control area operations in real-time or in planning for the hours and days ahead is such that increased knowledge of what will happen correlates strongly to

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5 Electric machinery requires two components of current to operate: power producing current and magnetizing current. Power producing or working current is current that is converted by the equipment into work. The unit of measurement of active power is the Watt. Magnetizing current, also known as reactive current, is the current required to produce the flux necessary to the operation of electromagnetic devices. Without magnetizing current, energy could not flow through the core of a transformer or across the air gap of an induction motor. The unit of measurement of reactive power is the VAR. Management of reactive power is the primary mechanism for controlling voltage at points within the network. System operators dispatch various devices capable of producing reactive power, including generators, shunt capacitor banks, static VAR compensators, etc., to control voltages in response to continually varying customer demand.

better strategies for managing the system. Much of this process is already based on predictions of uncertain quantities. Hour-by-hour forecasts of load for the next day or several days, for example, are critical inputs to the process of deploying electric generating units and scheduling their operation. While it is recognized that load forecasts for future periods can never be 100 percent accurate, they nonetheless are the foundation for all of the procedures and processes for operating the power system. Increasingly sophisticated load forecasting techniques and decades of experience in applying this information have done much to lessen the effects of the inherent uncertainty.

The nature of its fuel supply is what distinguishes wind generation from more traditional means for producing electric energy. The electric power output of a wind turbine generation is primarily a function of the speed of the wind passing over its blades. The speed of this moving air stream exhibits variability on a wide range of time scales – from seconds to hours, days, and seasons. The degree to which these variations can be predicted with some level of accuracy also varies. It should be noted that this is not an entirely unique situation for electric generators. Hydroelectric plants, for example, depend on water storage that can vary from year to year or even seasonally. Generators that rely on natural gas as their sole fuel source can be subject to supply disruptions or storage limitations. That said, the overall effects of the variable fuel supply are significantly larger for wind generation.

Impacts on the operation of the transmission grid and the control area relative to wind generation are dependent on the performance of the wind plants within that area as a whole, as well as on the characteristics of the aggregate system load and the generation fleet that serves it. Large wind generation facilities that are connected directly to the transmission grid employ large numbers of individual wind turbine generators. Individual wind turbine generators that comprise a wind plant are usually spread out over a significant geographical expanse. This has the effect of exposing each turbine to a slightly different fuel supply. This spatial diversity has the beneficial effect of "smoothing out" some of the variations in electrical output. The benefits of spatial diversity are also apparent on larger geographical scales, as the combined output of multiple wind plants will be less variable than with each plant individually.

The system load itself exhibits some unpredictable variations, both within an hour and over the course of the day. Because system operators are concerned with the balance of net load to net generation in their control area, load and wind variations cannot be considered separately. The impact of uncorrelated variations in load and wind over time will be considerably less than the arithmetic sum of the individual variations. This aggregation effect is already a critical part of control area operations, as responding to or balancing the variations in individual system loads, rather than the aggregate, would be exorbitantly complicated and expensive, as well as non-productive.

Wind generation forecasting is acknowledged to be very important for continued growth of the industry. Despite the increasingly sophisticated methods used to forecast wind generation, and the improving accuracy thereof, it is certain that large amounts of wind generation within a grid control area will increase the overall demand for ancillary services. Very large amounts of wind generation may result in redeployment of certain existing generating units, as the projected costs of wind energy going forward are expected to continue declining. Higher cost conventional units would then be displaced, possibly being relegated to assisting with the management of the control area, which is the subject of the following paragraphs.

Assessments of Ancillary Service Requirements and Impacts on Power System Operations

Within the wind industry and for those transmission system operators who now have significant experience with large wind plants, the attention has turned to not whether wind plants require such support but rather to the type and quantity of such services necessary for successful integration. With respect to the ancillary services listed earlier, there is a growing emphasis on better understanding how significant wind generation in a control area affects operations in the very short term – i.e., real-time and a few hours ahead – and planning activities for the next day or several days.

A number of recent studies have considered the impact of wind generation facilities on real-time operation and short-term planning for various control areas. The methods employed and the characteristics of the power systems analyzed vary substantially. There are some common findings and themes throughout these studies, however, including:

- Despite differing methodologies and levels of detail, ancillary service costs resulting from integrating wind generation facilities are relatively modest for the growth in U.S. wind generation expected over the next three to five years.
- The cost to the operator of the control area to integrate a wind generation facility is obviously non-zero, and increases as the ratio of wind generation to conventional supply sources or the peak load in the control area increases.
- For the penetration levels considered in the studies summarized in the paper (generally less than 20 percent) the integration costs per MWH of wind energy were relatively modest.
- Wind generation is variable and uncertain, but how this variation and uncertainty combines with other uncertainties inherent in power system operation (e.g. variations in load and load forecast uncertainty) is a critical factor in determining integration costs.
- The effect of spatial diversity with large numbers of individual wind turbines is a key factor in smoothing the output of wind plants and reducing their ancillary service requirements from a system-wide perspective

Where do Ancillary Services “Come From”?

Meeting the operational objectives for the power system is accomplished through coordinated control of individual generators as well as the transmission network itself and associated auxiliary equipment such as shunt capacitor banks.

How individual plants are deployed and scheduled is primarily a function of economics. Historically, vertically-integrated electric utilities would schedule their generating assets to minimize their total production costs for the forecast load while observing any constraints on the operation of the generating units in their fleet. In bulk power markets, competitive bidding either partially or wholly supplants the top-down optimization performed by vertically-integrated utilities. In either case, the economics of unit power production have the primary influence on how a plant is scheduled.

In addition, the entity responsible for the operation of the control area – an individual utility or a regional transmission organization, for example – must manage some generating units to regulate frequency and control power exchanges in real time, to make up discrepancies between actual and forecast loads, and provide adequate reserves to cover an unexpected loss of supply.

The efficiency of thermal generating units typically varies with loading, so for each unit there is a point at which the cost of energy produced will be minimum. For large fossil-fired and nuclear generating units, the cost of generation generally declines with increasing loading up to rated output. As a result, economics dictate that these units be "base loaded" for as many hours as possible when in operation.[6] Other factors, such as thermal system time constants or mechanical and thermal stresses may also result in certain units being loaded at fairly constant levels while online.

Against these operating constraints for certain units, other generating resources are deployed and scheduled to not only produce electric energy but also to provide the flexibility required by the operators to regulate system frequency, follow the aggregate system load as it trends up in the morning and down late in the day, and provide reserve capacity in the case of a generating unit or tie line failure. Some of these functions are under the auspices of a central, hierarchical control system generally referred to as automatic generation control or AGC. Others are the result of human intervention by the control area operators. In either case, the generating units participating in the system control activities must:

- Be responsive to commands issued by the control area EMS (energy management system), otherwise known as "being on AGC". Participating in AGC generally requires a specific infrastructure for communications with control center SCADA (System Control and Data Acquisition) system.
- Operate such that there is the appropriate "head room" to increase generation or reduce generation without violating minimum loading limits if commanded by the system operator or energy management system.
- Be able to change their output (move up or down, or "ramp") quickly enough to provide the required system regulation

As the electric power industry evolves, it is increasingly likely that third-party generators will play a large role in control area operations through various mechanisms and markets for ancillary services. One such mechanism is the short-term "imbalance market," sometimes conducted on an interval as short as five minutes, where generators bid to help the control area operators make up for real-time mismatches between control area supply and demand. Capacity markets are being developed in some parts of the country as a means for insuring adequate reserve generation and system reliability.

6The term "base loaded" is generally used to describe the operation of large generating units with high capital and operating costs but low fuel costs that are loaded to near maximum capability for most of the hours they are in service. In traditional electric utility system planning, the "base load" is sometimes defined as the minimum hourly system demand over the course of a year.

Project Overview

Objectives

A two-phase project was defined to address the issues and questions stemming from the Colorado Public Utilities Commission Order and Stipulation. Phase I of the project was to:

- Estimate the ancillary service costs of 720 MW (220 MW existing + 500 MW from renewable RFP) of nameplate wind based on its 2007 peak demand, which peak demand is projected to be 7,148 MW, or the best available peak demand forecast at the commencement of the study (~10% penetration).
- The ancillary cost estimate should provide an estimate of all PSCo's generating units' (owned and/or controlled under tolling agreements) cost factors – including regulation, load following, and unit commitment (including start up costs and ramp rates).
- Estimate the ancillary service costs of a quantity of nameplate wind at 15% penetration based on its 2007 peak demand (or the best available peak demand forecast at the commencement of the study).
- Include one full year's worth of data from the Lamar wind project.
- Keep Commission staff inform of study progress and invite Staff to participate in technical review meetings.

In a follow-on Phase II effort, the scope was defined to determine the sensitivity of the results from the initial phase to various aspects of how wind generation might be developed in the state. Specific items from the order and stipulation to be assessed include:

- Determine whether ancillary costs remain nearly the same for different sized facilities within certain ranges. The Commission will not specify the range, but instead instructs PSCo to examine the data to determine if it is appropriate to assume different ancillary costs depending upon size and geographic region, instead of a system-wide figure.
- The study should analyze the effect of contracted wind bidder projects on PSCo's system, because ancillary costs may vary significantly based on wind penetration level, geographic location, and diversity of wind resources, and these factors can not be fully considered until Renewable RFP projects are under contract.

Approach

The general approach employed for a 2004 study of the Xcel-NSP control area in Minnesota was the starting point for the Phase I effort. This analytical methodology is based on chronological simulations of power system scheduling and real-time operation. After discussions with PSCO personnel and project sponsors, several modifications to this basic approach were made to better adapt it to specific study needs.

Models and Data

Per the Order and Stipulation, CY2007 was the focus of the study. This year is characterized by:

- A (modified) projected peak load of 6922 MW
- Projected energy requirements of 34,224 GWH
- Approximately 15 MW of customer-sited solar electric power
- Updates to various existing power purchase and sale contracts

The chronological simulation methodology requires extended sets of hourly data. The preference is for this data to be based on recent historical years so that the daily patterns are representative of the behavior of actual system loads. In this vein, it is also important that the chronological wind generation data be drawn from same historical year so that correlations between wind and load due to meteorology are represented in the input data.

Historical load data from three years – 2002, 2003, and 2004 – was used to develop the hourly load patterns. The data sets were scaled so that the peak hour matched that projected for the study year.

Other types of archived data were also collected to define the study year, including:

- Day-ahead forecasts of hour-by-hour load, which is used for forward scheduling and power marketing activities in addition to nomination of natural gas for both direct use and gas-fired generation
- Planned, maintenance, and forced outage history for generating units
- Solar insolation data, used to construct an hour-by-hour production pattern for the customer-sited solar electric resources

Assumptions

The methodology used in this study is designed to mimic the day-ahead activities aimed at developing the best plan for meeting load. This plan is then tested against the actual control area demand that materializes. The actual control area demand is net of wind generation, which was assumed to be included in the scheduling process via next-day forecasts.

Other assumptions include:

1) Wind – Amount, location, and characteristics to be determined by modeling.
    a. 10 % (720 MW)
    b. 15 % (1,080 MW
    c. 20 % (1,440 MW)
    d. All-in Energy Price= $37.87 - Flat (Weighed average prices of 3 Renewable RFP bids)

Note that wind generation price or cost is not a factor in the analysis to follow. It is assumed that wind generation is a “must take” resource, and the PSCO will manage its other generation resources to accommodate wind. The costs associated with using these resources to manage wind – opportunity costs, higher production costs due to less-than optimal operations, etc. – is defined as integration cost in this study.

2) New Thermal Resources
    a. Type = Three (3) Generic Combustion Turbines in 2007
    b. Ratings - Summer = 120 MW (each); Winter = 139 MW (each)

c. Heat Rate = 10,450 MMBTU/MWh

d. Variable O&M = $4.30/MWh

e. Fixed O&M = $ 10.74 kW-yr (based on 160 MW design)

f. Min/Max Loading

i. 25% = 17, 568 MMBTU/MWH

ii. 50% = 12,759 MMBTU/MWH

iii. 75% = 11,204 MMBTU/MWH

iv. 100% = 10,450 MMBTU/MWH

g. Min Run Time = 4 hours

h. Max # of starts/day = 2 times

i. Start-Up Costs = $6,000

3) Solar

a. (Need for roughly 10-15 MW with half at customer on-site)

b. Modeled based on historical solar insolation data for study period

4) Contract Extensions

a. Colorado Power Partners (CPP) – Brush 1& 3 (75 MW)

b. current end date of 10/2005

5) Gas Prices

a. Per PSCO internal forecasts

b. Documented in Table 6

Table 6: Assumed Natural Gas Prices for Calendar Year 2007

Month	Price ($/MMBTU)
Jan	$8.64
Feb	$6.87
Mar	$7.09
Apr	$6.93
May	$6.58
Jun	$5.44
Jul	$4.65
Aug	$4.78
Sep	$4.51
Oct	$3.99
Nov	$6.37
Dec	$6.60
Average	**$6.04**

Developing the Wind Generation Model

A chronological representation of wind energy production is essential for the methodology in this study. This data needs to accurately portray the following characteristics:

- The effect of spatial diversity within large wind plants, where the faster fluctuations in production from individual turbines are relatively uncorrelated, leading to a much smaller normalized variations in the output of the entire plant;
- The effect of geographic diversity between large wind plants located miles to hundreds of miles apart. The effect is similar to spatial diversity, but at larger time increments;
- Correlation in production between geographically-separated wind plants since the fuel source is driven by a common meteorology. Large weather systems, for example, with affect all plants in the region, albeit not simultaneously.
- Effects of topography, where terrain features can enhance the wind resource potential by steering or funneling near-surface winds.

Also, as mentioned previously, correlation between wind generation and load may be an important factor to capture. Meteorological conditions that contribute significantly to peak load hours and days may also favor a certain wind regime.

The challenges associated with developing a data set with attributes as described above are significant. There are really only three possible sources for such data:

1. Long-term wind speed measurements (of sufficient temporal resolution) from hub-height anemometers at each of the wind resource areas of interest. Multiple towers are desirable for regions where significant development would be possible.
2. Long-term production measurements (again, of sufficient temporal resolution) from existing wind plants. Such data allows operation of the existing facilities to be completely characterized, but provides little or no information for new or prospective sites.
3. Time-domain simulation of the meteorology of over the entire region using one of the physics-based atmospheric models. If results consistent with historic weather patterns are desired, archived observation data would be required to keep the simulation tracking what actually occurred, rather than generating its own (but still physically consistent) version of the weather for that period.

The third approach above was first applied for the previous Xcel-NSP study with very favorable results, and was chosen as the method for developing the chronological wind speed data for this project.

Synthesizing Chronological Wind Speed Data

Based on locations of existing wind generation facilities, known wind resource areas, and prospective wind project activity, the project team in consultation with Xcel identified locations within or near to the Xcel Colorado service territory to be considered in this study. Figure 14 shows the specific locations identified. Each numbered point represents an imaginary meteorological tower that was "inserted" into the computer model to extract certain variables from the computer model as the simulation progressed.

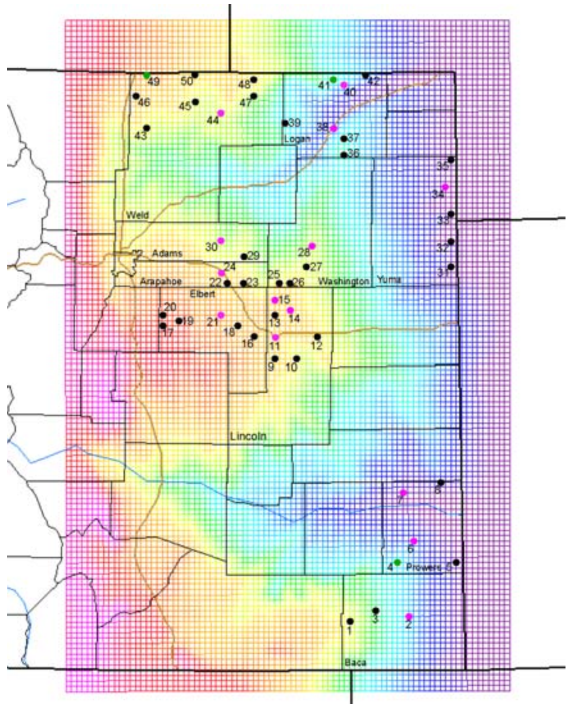

Figure 14: Placement of "proxy" towers at which hub-height wind speed data is to be saved from the meteorological simulations. Background colors on map indicate elevation (red= high, blue=low)

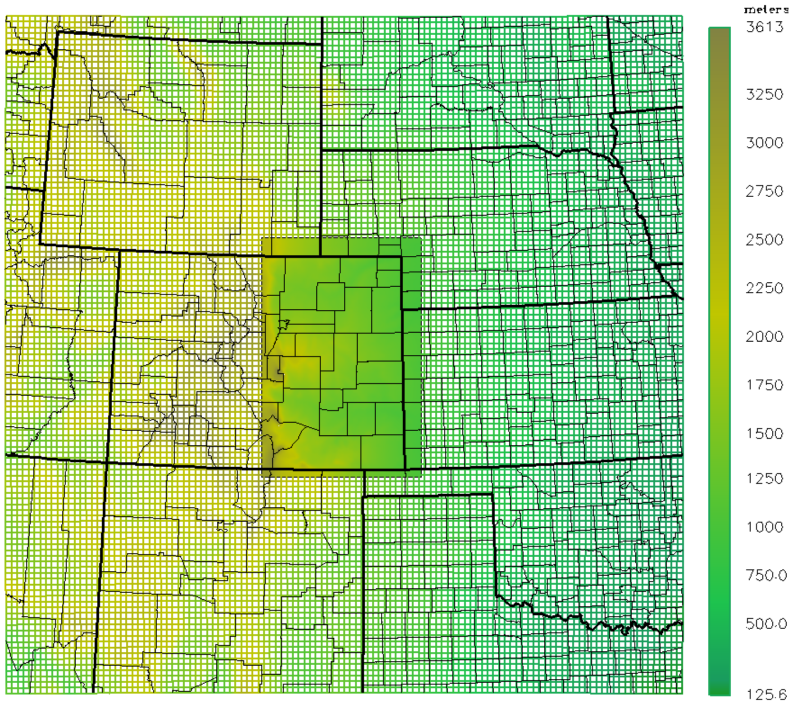

Figure 15: Region of inner-most nested grids in MM5 model.

The base MM5 model consists of cells of 20 to 40 km on a side, and uses 33 separate layers to represent the vertical dimension from the surface to the top of the atmosphere.

To re-create the atmospheric conditions over eastern Colorado for 2002, 2003, and 2004 (the base years for the study), the model was augmented by adding two nested inner grids of smaller dimension as shown in Figure 15. Temperature, pressure, and wind speed at 80 m above the surface level (approximate hub-height for the current generation of commercial wind turbines) were stored at ten-minute for the smallest grids designated as a "proxy" met tower location.

A custom multiple-process computer system is used to run the simulation model. Simulation time for the Colorado model utilizing two banks of a dozen processors each amounted to about three weeks for each annual data set.

The data produced by the MM5 simulation is effectively equivalent to what would be available from a long-term resource monitoring effort over the same years at each of the 50 proxy towers or extraction points in the model.

Definition of Wind Generation Scenarios

Figure 16 shows the "proxy tower" locations from the WindLogics MM5 simulation model run for the calendar years 2002, 2003, and 2004. The primary output of the model for each of these locations is a three-year time series of wind speeds corresponding to a 80 m AGL (above ground level) wind turbine hub height at ten minute resolution.

To create the wind generation models to be used for assessing impacts on the PSCO system, wind speed time series at some or all of these proxy tower locations must be converted to wind generation. The first step in this part of the process is to construct a scenario of wind generation development for the two wind penetration levels to be considered (10% and 15%). To properly account for increasing spatial and temporal diversity as the amount of wind generation increases, only a portion of the towers should be used for the lower penetration scenario, saving additional tower data for the expanded scenario. In addition, the model will be somewhat more realistic if the amount of wind generation at each location is kept smaller.

The two scenarios to be considered for the study amount to nominally 720 MW and 1080 MW of wind generation respectively. Given that there are a total of fifty towers, limiting the amount of wind generation at each point to 30 MW or less would allow both scenarios to be comfortably represented. It would also allow a 20% or 1440 MW scenario to be constructed from the existing data without reusing towers.

Existing and prospective wind generation projects in PSCO service territory are shown in Table 7. The existing generation at Peetz, Ponnequin, and Colorado Green totals 220 MW. The others projects under negotiation for which the location and prospective capacity are known, or are being considered but not as far along in the process. Prospective projects are indicated by the larger dots in Figure 16.

Ten percent is a convenient penetration level for the study. However, if the existing wind generation facilities are augmented by those designated as Prospective Projects 1, 2 and 4, the total generation to be considered would be just under 10%, or 704 MW.

A graphic of this proposed scenario for the 10% penetration is found in Figure 17. The circles bound the towers that would be used or considered to make up the facility.

Table 7: Existing and Prospective Wind Generation Projects for PSCO

Project	Capacity	Desired number of towers for representation
Colorado Green	162 MW	5 towers
Peetz	30 MW	1 tower
Ponnequin	30 MW	1 tower
Prospective Project #1	130 MW	4 towers
Prospective Project #2	199 MW	7 towers
Prospective Project #3	69 MW	3 towers
Prospective Project #4	153 MW	5 towers
Prospective Project #5	201 MW	7 towers

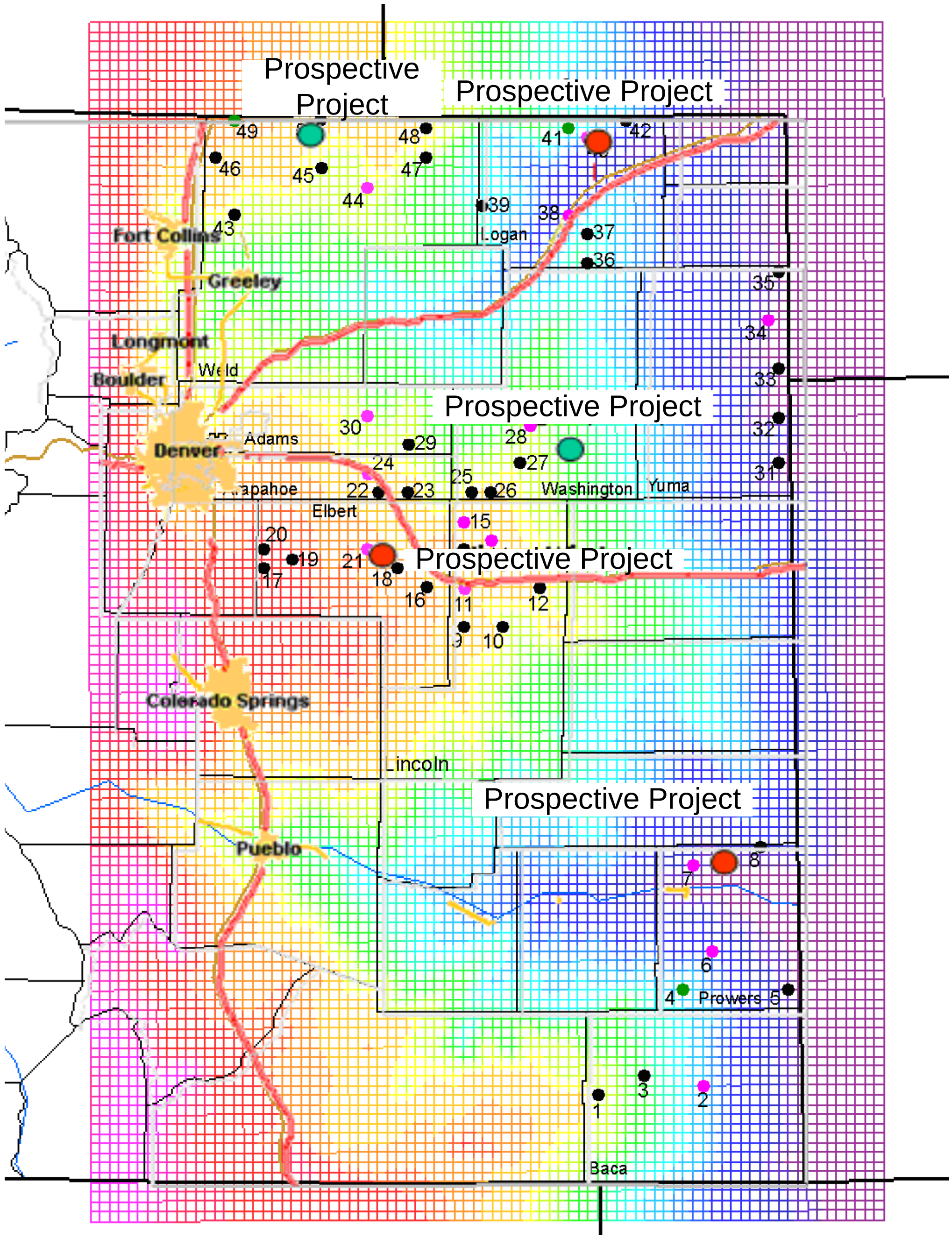

Figure 16: Proxy tower locations with overlay of projects under negotiation. Legend: Green = existing, magenta = talks underway or interest expressed, black = additional locations selected on basis of wind resource

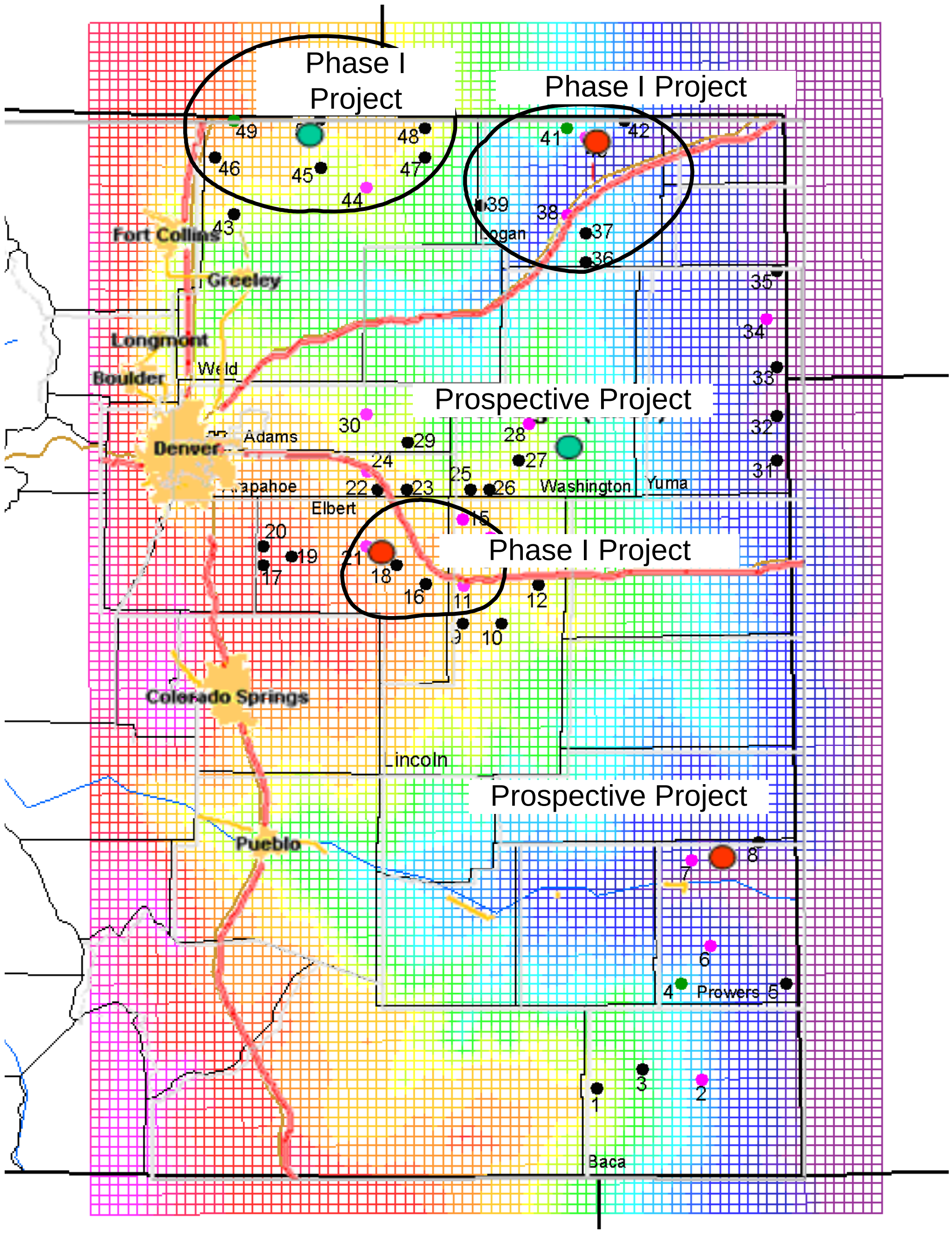

Figure 17: Proposed wind plant additions for Phase I scenario.

After internal discussions at Xcel, it was decided that the 10% scenario would include existing wind plants plus Prospective Projects 1,2, and 3 (Table 8). The ratings of the new plants were scaled so that the total wind generation in the scenario sums to 722 MW. Proxy tower numbers selected to represent all wind generation in the 10% scenario are shown in Table 9.

Table 8: Phase I 10% Penetration Scenario for Xcel-PSCo Wind Integration Study

Project	Capacity	Rating for Study	Desired number of towers for representation
Colorado Green	162 MW	162 MW	5 towers
Peetz	30 MW	30 MW	1 tower
Ponnequin	30 MW	30 MW	1 tower
New Project 1	130 MW	165 MW	4 towers
New Project 2	199 MW	240 MW	8 towers
New Project 3	69 MW	95 MW	3 towers
Total	**620 MW**	**722 MW**	**22 towers**

Table 9: Proxy Tower Assignments to Phase I Wind Projects

Project	Rating for Study	# of Towers	Proxy Tower #'s
Colorado Green	162 MW	5 towers	1, 2, 3, 4 5
Peetz	30 MW	1 tower	41
Ponnequin	30 MW	1 tower	49
New Project 1	165 MW	4 towers	36, 37, 38, 39
New Project 2	240 MW	8 towers	21, 18, 16, 11, 13, 14, 15, 9
New Project 3	95 MW	3 towers	6, 7, 8
Total	**722 MW**	**22 towers**	

The wind generation scenario for 15% penetration or 1038 MW was developed by adding proxy towers and projects to the 10% scenario. Figure 18 illustrates both scenarios.

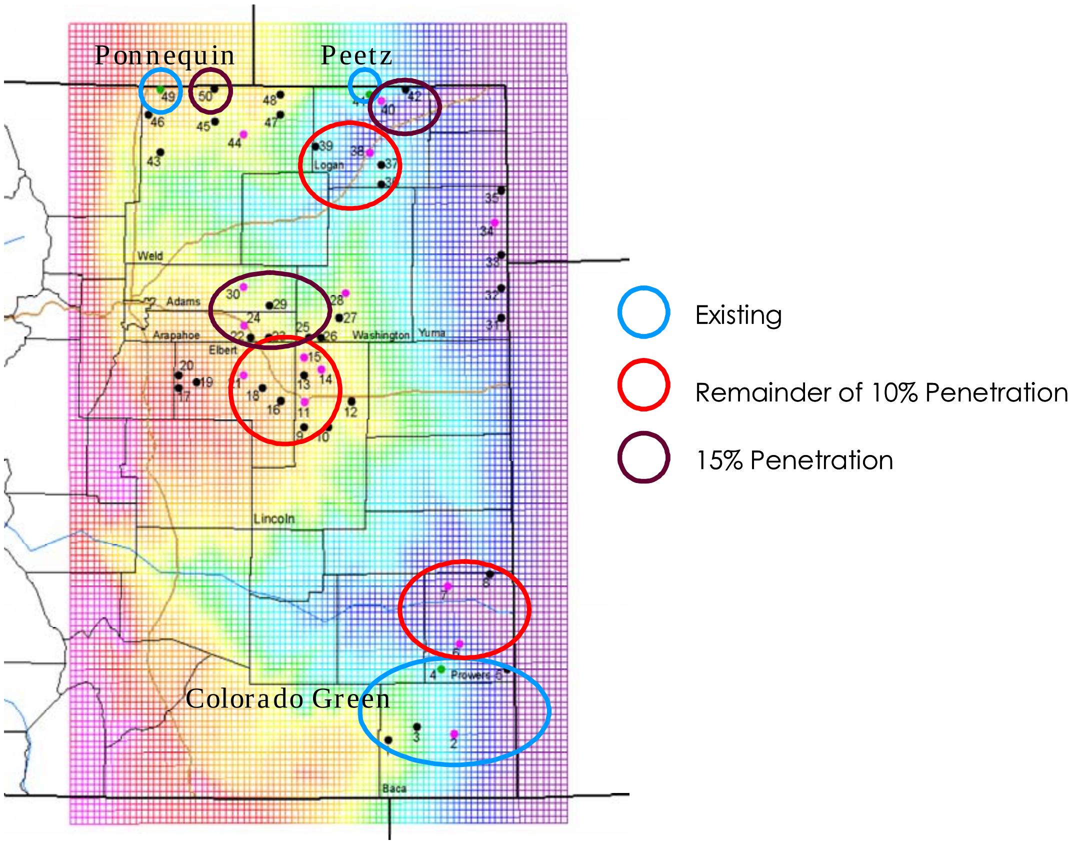

Figure 18: Final allocation of proxy towers by scenario.

Analysis of Wind Speed and Wind Generation Data from the Peetz Table Plant

In the 2004 study for Xcel-NSP, the wind speed time series data from the MM5 model runs was converted to wind generation by applying a simple turbine power curve to values at the top of each hour. In the validation exercise, the calculated production time series data was shown to track the measured data reasonably well. Some differences were very apparent, though – namely the periods of vigorous winds where the calculated value remained at the maximum rating while the measured data retained some degree of variability.

The project team had several discussions about how the transformation of wind speed data to generation might be improved, although it was recognized that the simple approach was likely more than adequate for the project purposes. Since an objective of the project team was to improve the methodology where possible in this second study for Xcel, a re-evaluation of the method for computing wind generation was warranted.

PSCO provided 10-minute wind speed data and hourly generation data for the Peetz Table Wind Plant for calendar year 2004. Figure 19 contains a couple of snippets of this data. The hourly wind speed data shown is the average of the preceding six ten-minute values.

An x-y representation of the generation and wind speed data yields a fuzzy "power curve" for the plant, which is shown in Figure 20.

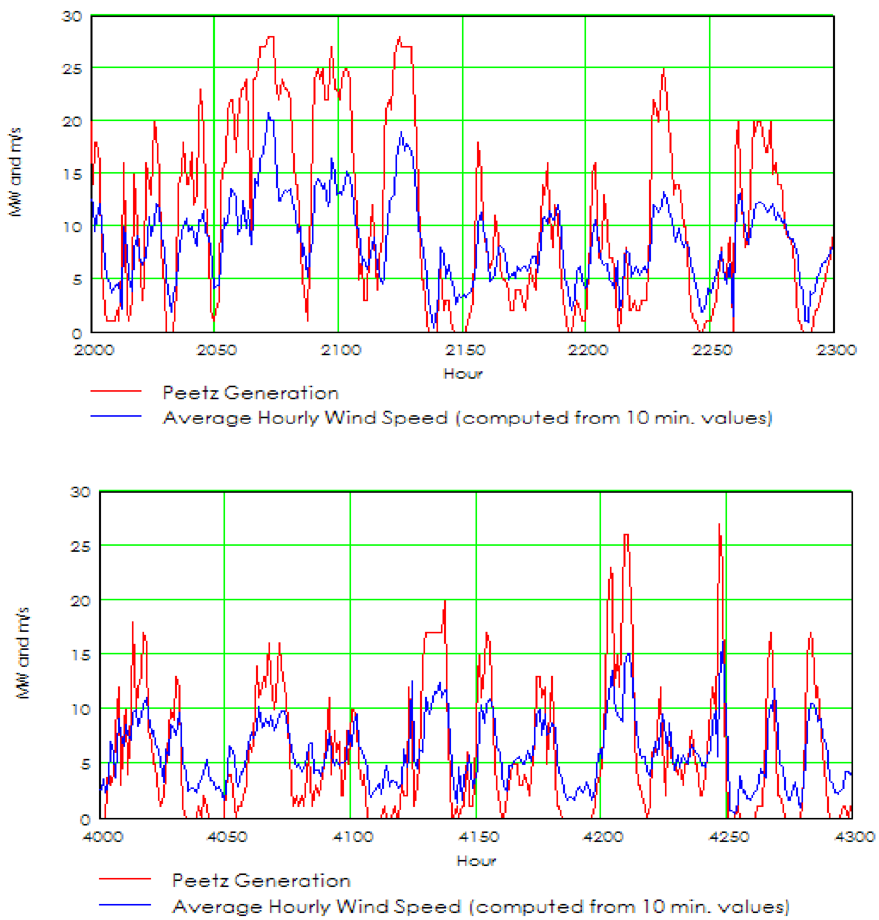

Figure 19: Peetz generation and wind speed for two periods in 2004.

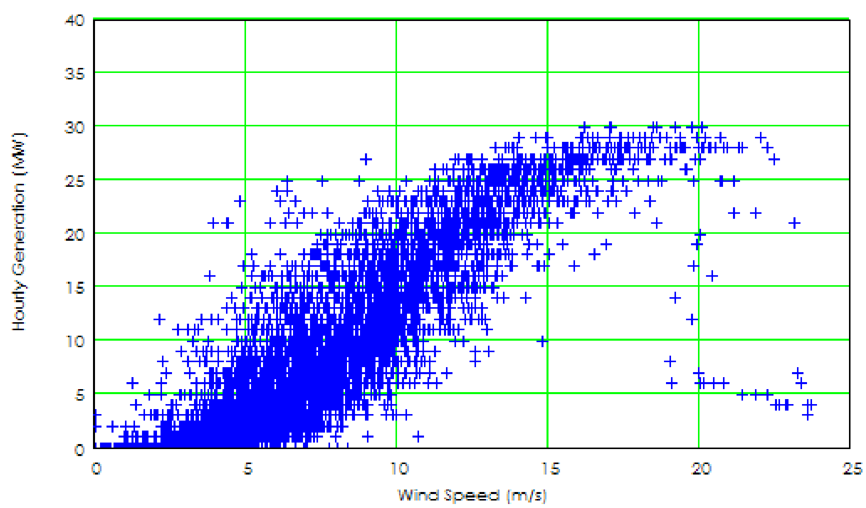

Figure 20: Empirical "Power Curve" for Peetz plant from measured values.

The objective of this exercise is to determine a method for calculating hourly wind generation from the measured wind data. The turbine power curve from Figure 21 is used (although the turbines at Peetz are actually the smaller 900 kW units from NEG_Micon).

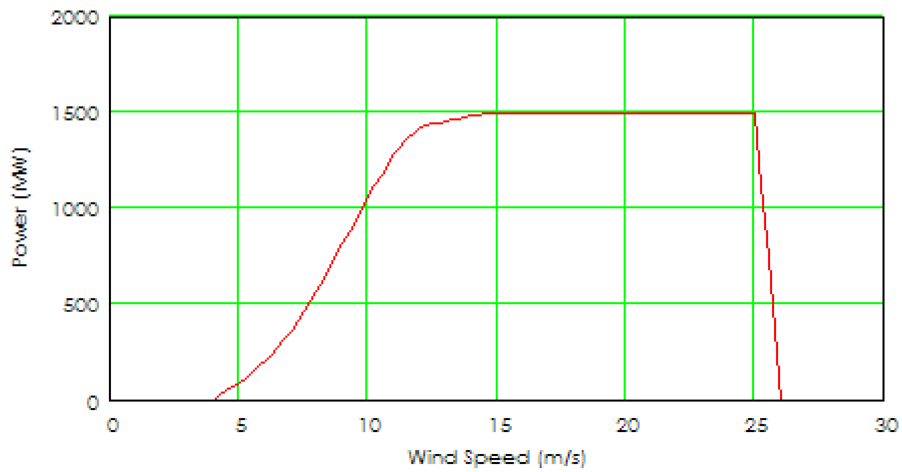

Figure 21: Turbine power curve used for calculating Peetz generation data from wind speed measurements.

Figure 22 shows the results of applying the power curve (scaled appropriately) to the measured 10-minute wind speed data for CY2004, then aggregating the results to hourly average values. The striking feature of this figure is the "fuzziness." If the wind speed data were averaged to hourly values before applying the power curve, the characteristic would match that shown in Figure 21. The difference, of course, is that the mathematical operations are not the same because of the nonlinear nature of the turbine power curve.

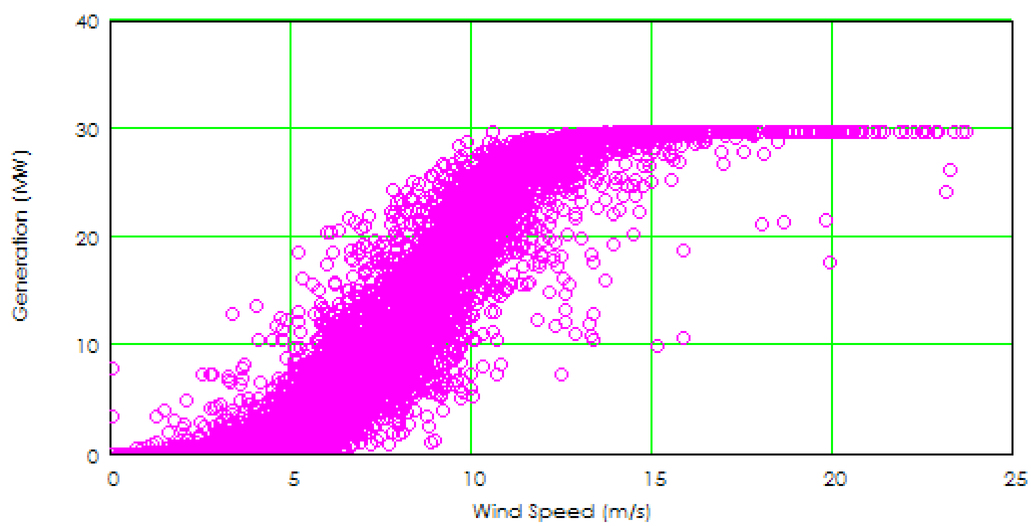

Figure 22: Peetz "power curve" calculated from 10-minute wind speed values.

A closer comparison (Figure 23) of the calculated and measured wind generation reveals that the simple transformation from wind speed to power using a single power curve and wind speed value leads to what was observed in the Minnesota data – the calculated value is higher than the actual, and tends to “saturate” during periods of high wind, sometimes unlike the measured data. A computation of the energy delivered shows that the calculated value is about 25% higher than what was actually metered.

Figure 24 illustrates this qualitatively. The “knee” of the calculated plant power curve is much more pronounced, although the “fit” is reasonable at lower power levels. Therefore, while shifting the plant power curve to the right to approximately account for the diversity of wind speeds over the plant area would degrade the fit at lower wind speed levels.

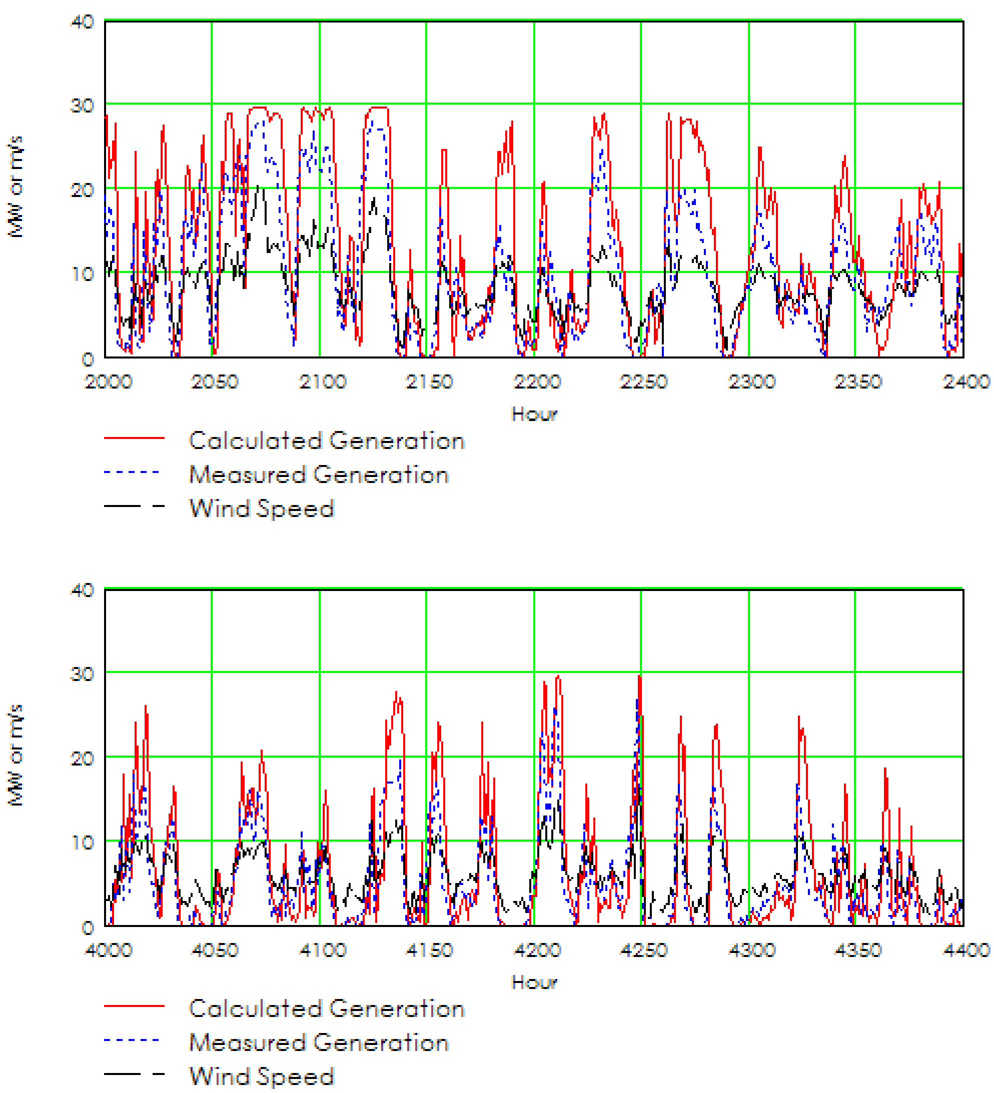

Figure 23: Calculated vs. Measured wind generation.

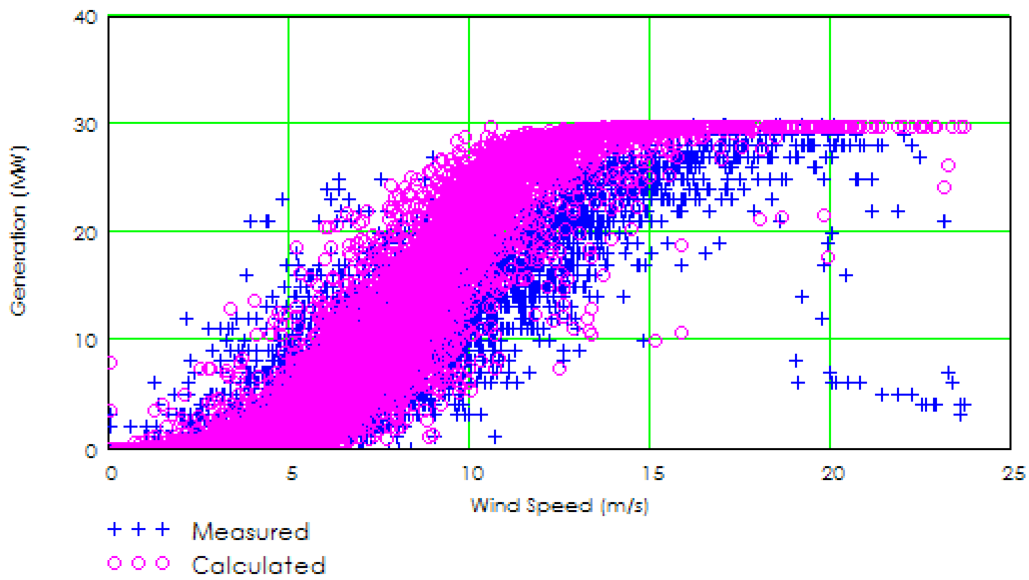

Figure 24: Measured and calculated plant power curves.

A better fit between the calculated and measured plant power curves (as well as the time series data) can be achieved by modifying the measured wind speed prior to applying the power curve. The modification consists of applying an exponent slightly less than one to the measured wind speed value. Figure 25 illustrates this for an exponent of 0.95. Note that the effect on low values of wind speed is much smaller than for larger ones. Also, for values well above the rated turbine wind speed, the modification makes no difference in the power calculation.

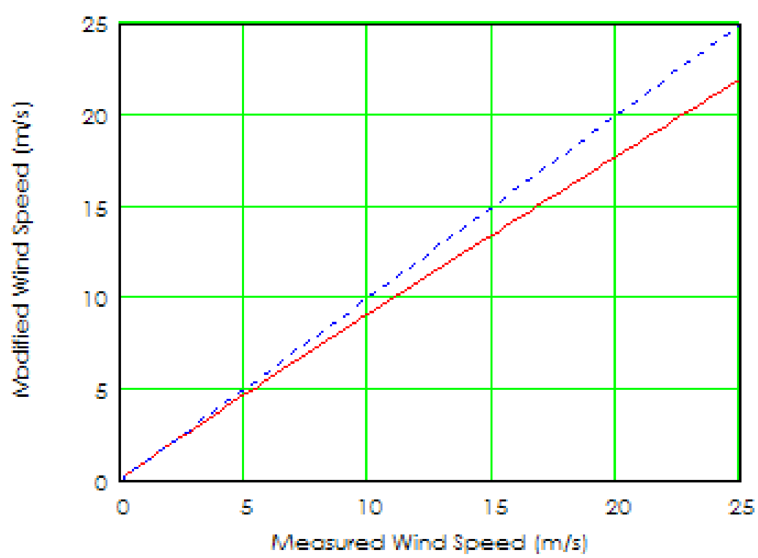

Figure 25: Exponential modification of measured wind speed.

The comparison of measured and actual power curves using this modification is shown in Figure 26. The calculated energy over the entire year for the calculated data differs by less than 1% from the measured data.

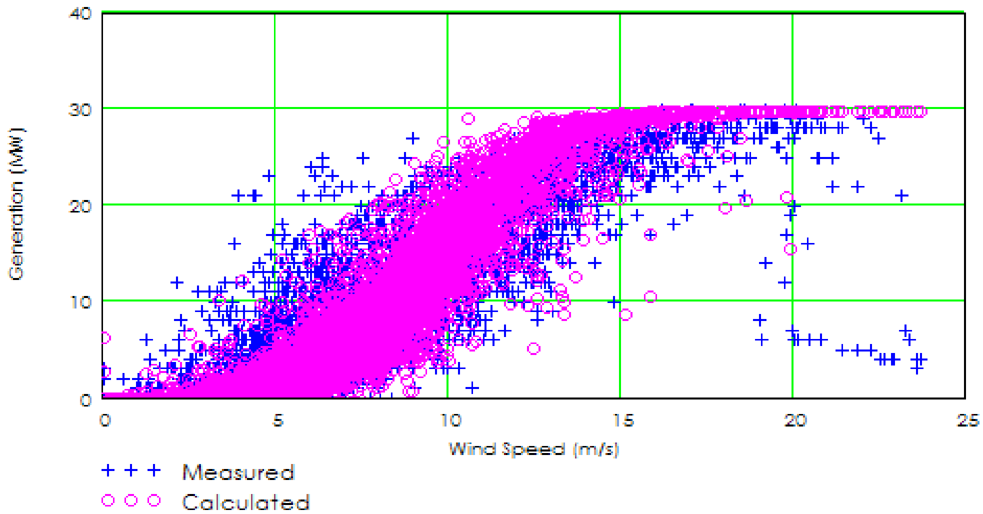

Figure 26: Measured and modified calculated plant power curves.

The improvement is also evident in the time series data. Figure 27 shows the same time periods from Figure 23, with the calculated value here based on a modified wind speed value. Note that while improvement is evident, the time periods selected for illustration are not the best ones to show the difference. Figure 28 provides a little better view.

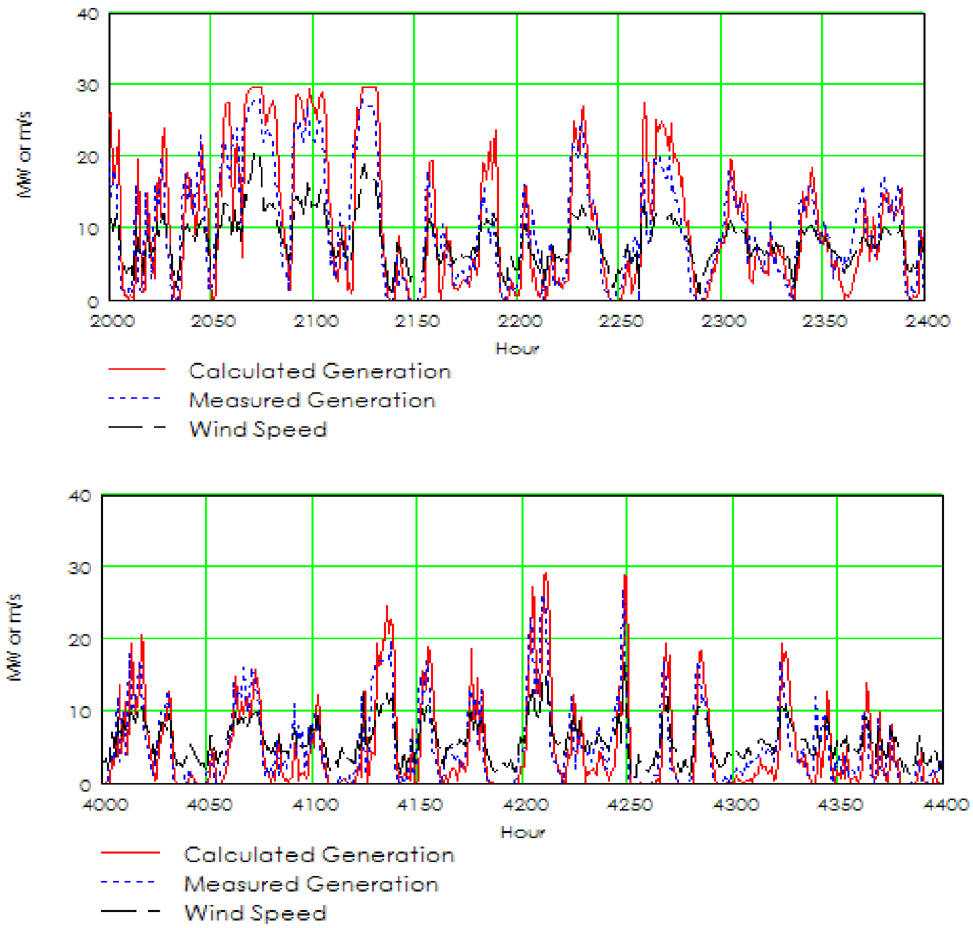

Figure 27: Comparison of measured wind generation to that calculated with wind speed modification.

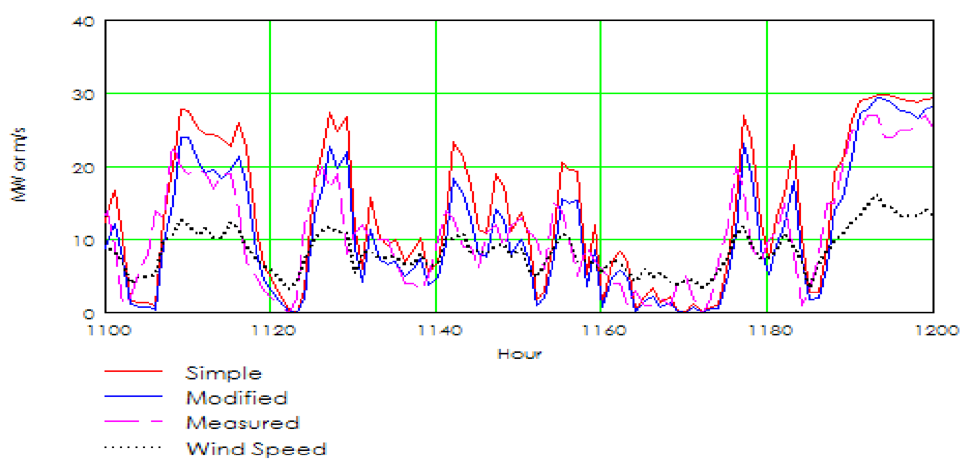

Figure 28: Another view.

Developing the Wind Generation "Model"

Using the findings from the Peetz analysis described in the previous section, the wind speed data synthesized with the MM5 atmospheric model was converted into a wind generation time-series. A view of four weeks of this data is shown in Figure 29.

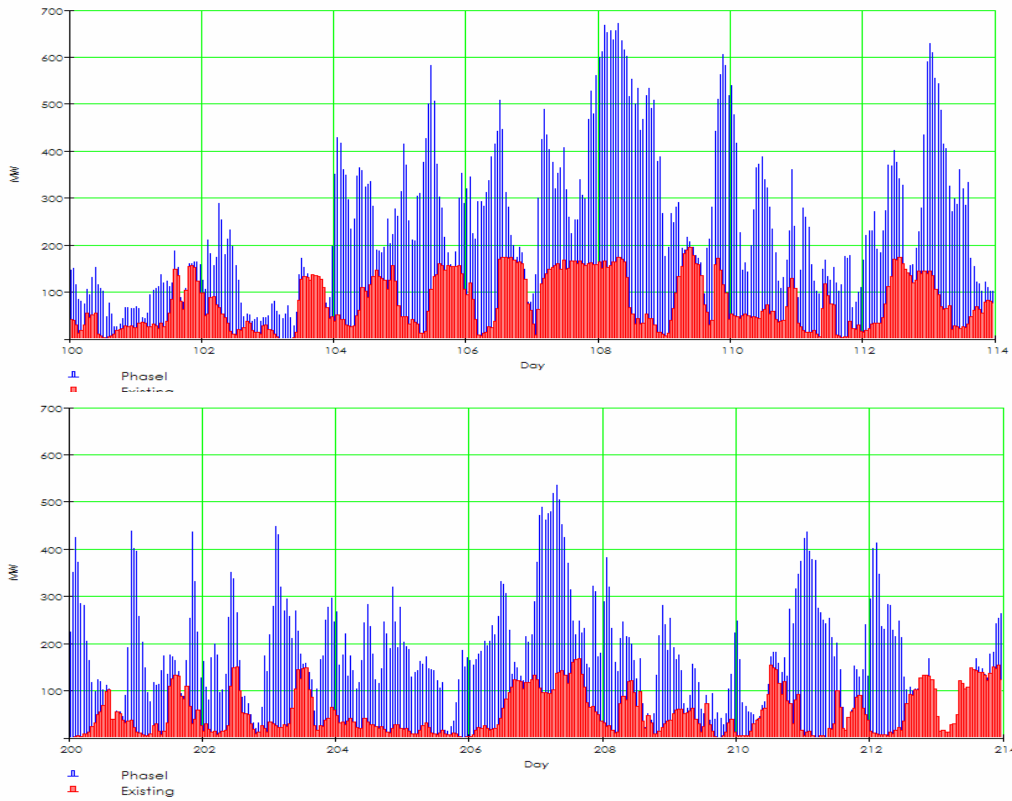

Figure 29: A view of the baseline wind data for the 10% penetration scenario.

Regulation and Load Following Impacts

Statistical Analysis of Regulation - Background

The basis for a statistical analysis of control area regulation requirements is described by Hirst and Kirby[7,8]. It relies on the notion that certain of the temporal variations in net control area load can be attributed to random activities and actions of all customer loads (and even some generators) that do not exhibit a distinct pattern, but rather have characteristics of "noise" on a detailed plot of aggregate system load. Figure 30 shows a one-hour measurement of system load superimposed on a measurement of the same load that is "smoothed" to reveal the underlying trend.

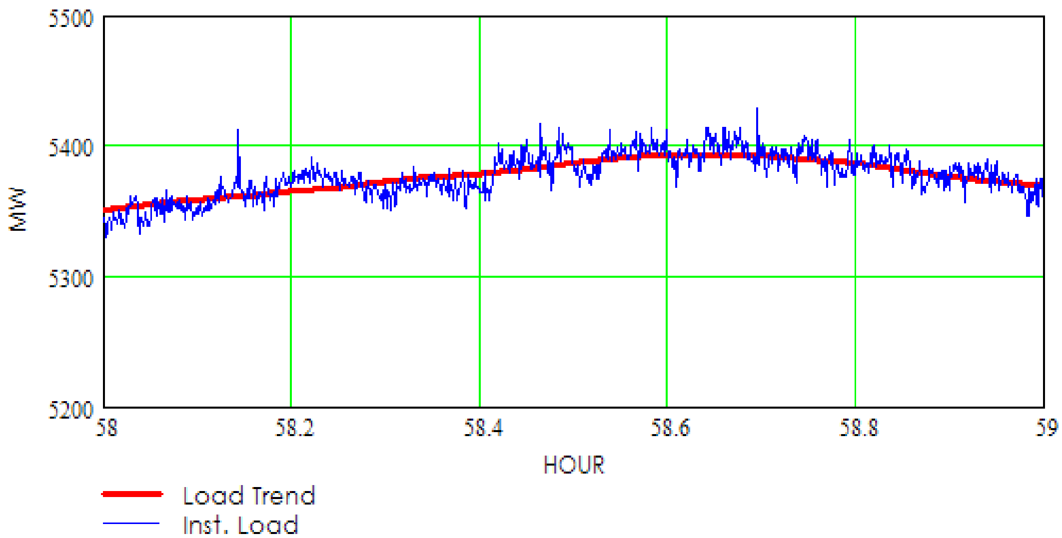

Figure 30: Instantaneous system load at 4 second resolution and load trend

Although the Hirst/Kirby method does not make any assumptions about correlations between subsets of the aggregate, a simplification can be made if the subsets are assumed to be uncorrelated, i.e. they are statistically independent. This allows the use of some straightforward algebra to analyze the impact of an individual portion of the aggregate load, and is very useful when considering the impacts of wind generation.

It should be noted that the statistical analysis described in the reference papers does not consider any specific details of the AGC load-frequency control algorithms or characteristics of the generating units providing regulation service. Nor does it explicitly address or mathematically relate to control performance as defined by the NERC standards CPS1 and CPS2. Rather, historical time-series load data is examined to simply quantify the range of regulation capability that would be required to compensate for the fast variations in net system load.

7Hirst, E. and Kirby, B. "Separating and Measuring the Regulation and Load Following Ancillary Services" November, 1998 (available at www.EHirst.com)

8Hirst, E. and Kirby, B. "What is the Correct Time-Averaging Period for the Regulation Ancillary Service?" April, 2000 (available at www.EHirst.com)

Separating the net system load fluctuations into two categories – fast, random fluctuations (with zero net energy) and a longer-term trend with variations – can be done by applying a rolling average computation (Figure 31) to time-series load data of sufficient resolution. The result of this calculation is then subtracted from the raw load data to extract the component of the overall fluctuation that is defined as regulation.

$$\text{Load following}_t = \text{Load}_{\text{estimated-}t} = \text{Mean}\ (L_{t-29} + L_{t-28} + \ldots + L_t + L_{t+1} + \ldots + L_{t+30})$$

$$\text{Regulation}_t = \text{Load}_t - \text{Load}_{\text{estimated-}t}$$

Figure 31: Equations for separating regulation and load following from load.

Application of the equations in Figure 31 to the raw load data from Figure 30 results in a regulation characteristic time series like that shown in Figure 32.

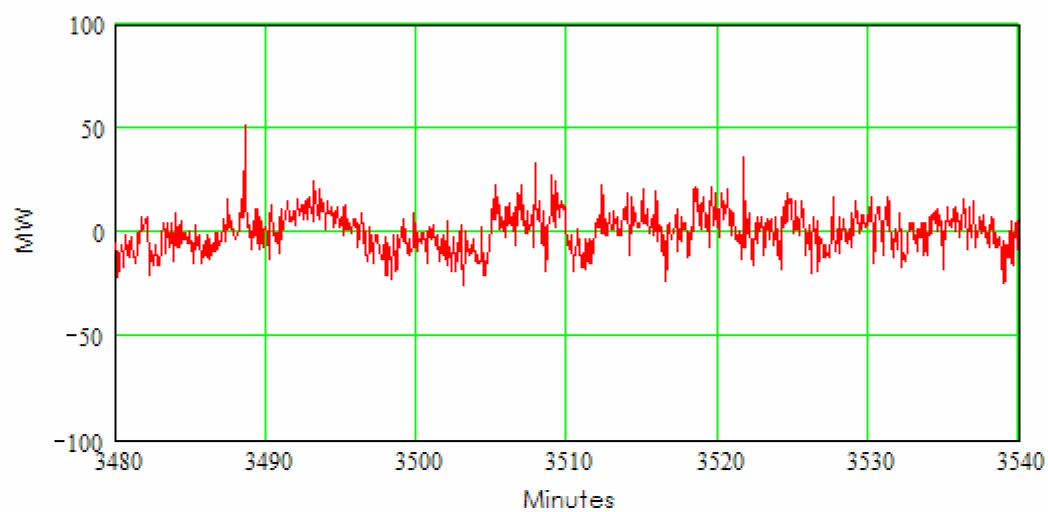

Figure 32: Regulation characteristics for raw load data of Figure 30.

Statistics for the resulting regulation time series are then generated. The standard deviation of the samples will depend to some degree on the resolution of the raw data; for the very high resolution 4 second data used in these illustrations the standard deviation will be higher than if the raw data (or the regulation characteristic itself) were integrated or smoothed by a rolling average function. In 8, the authors examined data from several control areas and found that the appropriate time period was likely one to two minutes, and is influenced by the one-minute time-averaging period of CPS1 and CPS2, system size, mix of generators on AGC, load composition, and AGC control logic.

The regulation requirement can be related to the standard deviation by applying a multiplying factor, e.g. 3 times the standard deviation to encompass 99% of all the deviations in the sample. From discussions with the authors of [7], the practice for operators in the U.S. appears to indicate a somewhat higher multiplier of the standard deviation, above 3 and ranging up to 5.

The above algorithms can be applied to the entire load or any subset for which suitable measurement data is available. If the regulation characteristics of the individual subsets are truly uncorrelated, the regulation characteristic of the combination can be calculated from the statistics of the individual characteristics as follows:

$$\sigma_T = \sqrt{\sum \sigma_i^2}$$

where

σ_i = standard deviation of regulation characteristic of subset of load

σ_T = standard deviation of regulation characteristics of total load

For purposes of this study, the individual components in the above equations will consist of each of the plants in the wind generation scenario and the total system load as projected for 2007.

Analysis of Xcel-PSCO Load

One week of high-resolution load data from each season was extracted from EMS archives as the basis for the determination of the existing regulation characteristic of the PSCO system load. Analysis of this archived data lead to a fairly significant finding with respect to wind generation impact – A large portion of the existing regulation requirement for the PSCO system is attributable to a single arc furnace load. The upper plot in Figure 33 shows a single day of the PSCO load at a time resolution of four seconds. The load characteristic net of the existing wind generation is also shown. In the bottom plot in that figure, wind energy delivery (about 222 MW nameplate) is plotted against the daily demand for the arc furnace.

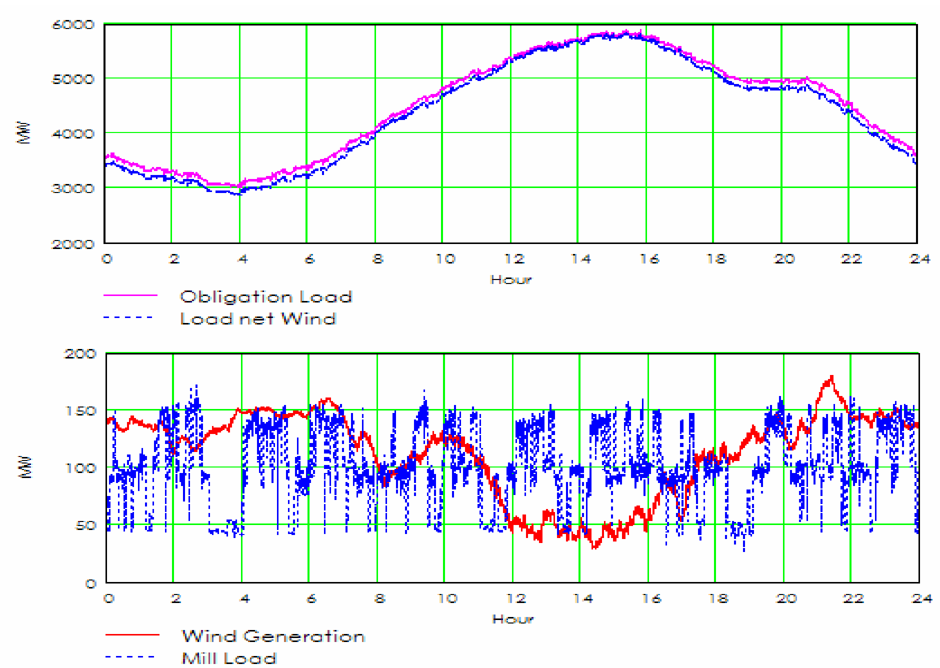

Figure 33: Top - High-resolution depiction of PSCO obligation load (with and without wind generation). Bottom – arc furnace load and wind energy production for same day.

Applying the rolling average technique previously described to the PSCO load data results in a trend and deviation time series as depicted in Figure 34. The top figure shows the instantaneous values (four second intervals) and the computed trend. In the bottom figure, the difference between the instantaneous value and trend is plotted for the obligation load data and for that data with the arc furnace load removed. The contribution of the arc furnace load to the system regulating requirement is obvious from both plots.

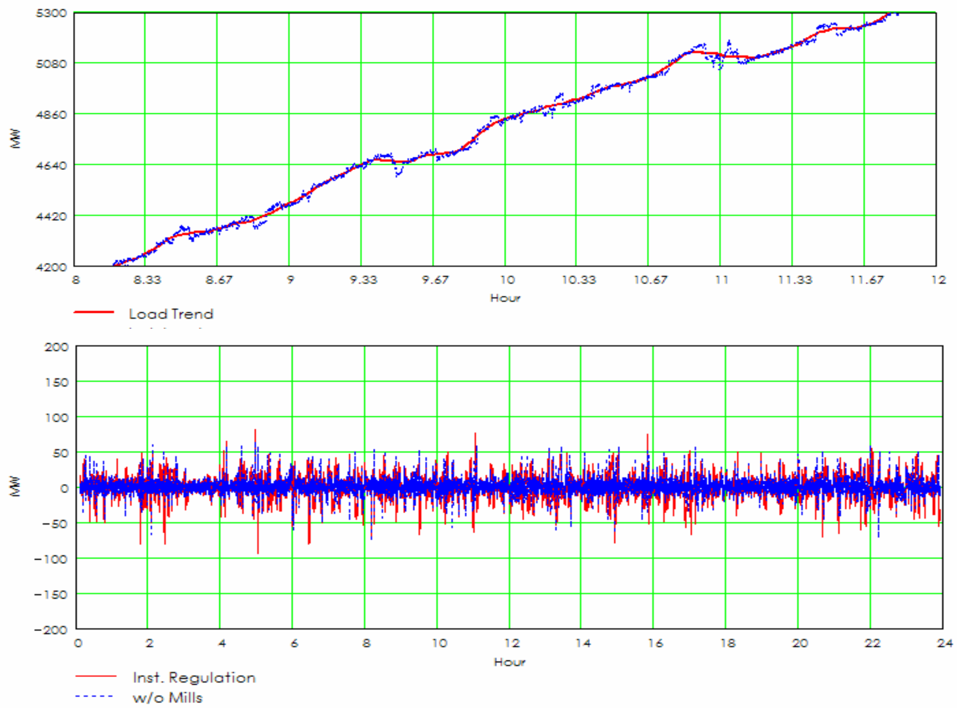

Figure 34: Application of rolling average filter to high-resolution load data. Top: instantaneous load and trend. Bottom: Regulation characteristic time series for obligation load, with and without arc furnace load.

Figure 35 further illustrates this contribution. Removal of the arc furnace load results in a much smoother load trend over the course of the 24 hour period.

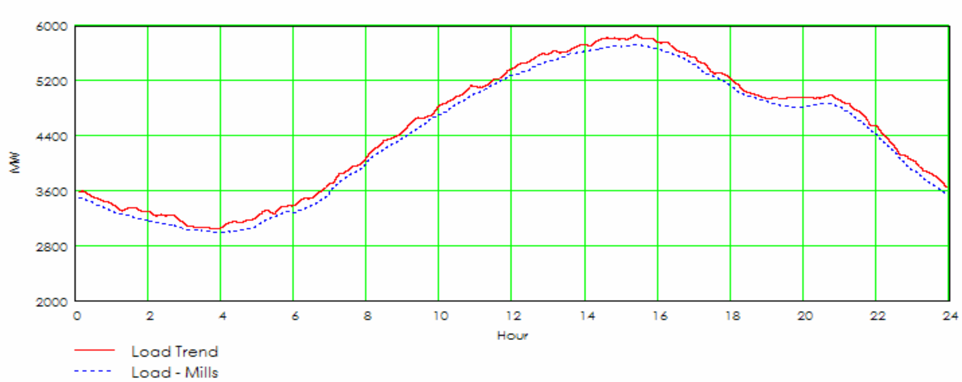

Figure 35: Typical daily load shown from high-resolution measurement data, with and without arc furnace load

Statistical analysis of the current load data shows that the standard deviation of the regulation characteristic averages 15.92 MW, with a few days either above or below this range. Results for one day are shown in Figure 36. Here, the arc furnace load is clearly shown to have dominant influence on the regulating requirement.

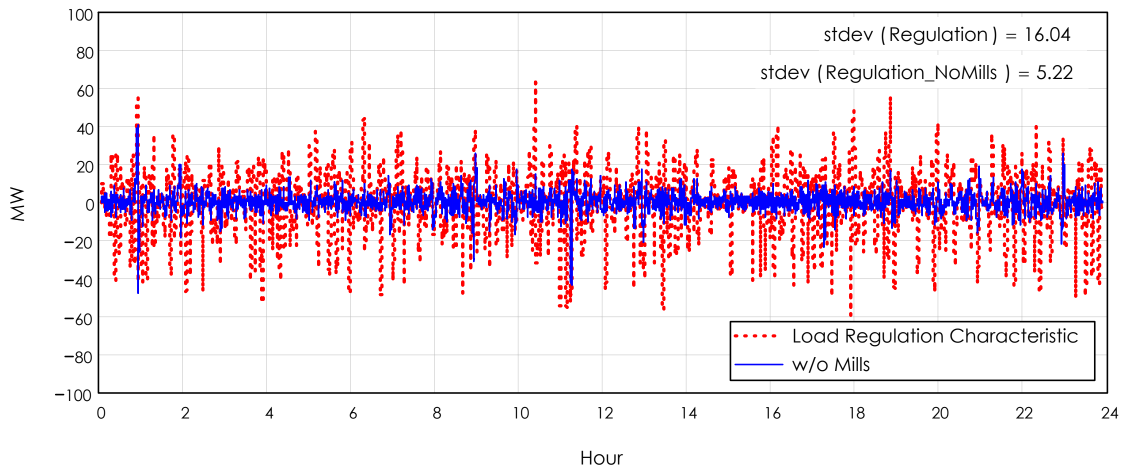

Figure 36: Regulation characteristics of PSCO obligation load and load without arc furnaces

Table 10 contains the complete statistics for each of the 28 days of load data analyzed, and also shows the influence of the existing wind generation in the PSCO system on regulation. Adding the 222 MW of wind generation to the obligation load increases the average standard deviation of the regulation characteristic only slightly, from 15.92 MW to 16.02 MW, or about 100 kW, using one-minute average data. The same result is obtained by processing wind and load data independently and then combining statistically, or by first netting the existing wind generation with load from the high-resolution archive data and then processing statistically. This cross-check affirms of the statistical independence of the high frequency variations in load and wind generation.

Based on these findings, the effect of new wind generation on the fast-responding regulation reserves for the PSCO control areas is projected to be very modest. From the table, a conservative assumption for the standard deviation of combined regulation characteristic for 220 MW of wind generation (consisting of one large and two smaller plants) is no more than 2 MW, or just under 1% of nameplate rating, which would be a conservative estimate of wind generation regulation characteristics. The standard deviation of the regulation characteristic at the projected levels of wind penetration can be estimated by statistically combining the standard deviations of the individual components. Reaching the 10% penetration level requires an additional 500 MW of wind generation. Using results from Table 10, and assuming this incremental amount is comprised of two additional 220 MW plant combinations plus another 60 MW, the standard deviation of the new load net wind regulating characteristics can be calculated:

$$\sigma_{total} := \sqrt{15.92^2 + 2^2 + 2^2 + 2^2 + .44^2 + .32^2}$$

$$\sigma_{total} = 16.302$$

This represents a 0.382 MW increase over that calculated for the load alone. Based on data provided by PSCO for this study, current practice reserves about 60 MW of up/down regulation capacity or 4 times the average standard deviation of the obligation load regulation characteristic. Using this multiplier, the incremental amount of regulation due to wind at the 10% penetration level is **1.53 MW**.

The analysis is extended to the 15% penetration level by assuming a total of five 220 MW segments of wind generation facilities, or 1100 MW:

$$\sqrt{15.92^2 + 2^2 + 2^2 + 2^2 + 2^2 + 2^2 + 2^2} - 15.92 = 0.616$$

$$4 \cdot (0.616) = 2.46$$

The incremental amount of regulation due to 15% wind generation penetration is estimated to be about **2.46 MW**.

The analysis says nothing about how the regulation burden should be allocated to the load, wind generation, or the arc furnace load, but instead simply determines how much total wind generation at the given penetration levels increases the requirement over that for the obligation load including the arc furnaces. Since regulation impacts are nonlinear, the first entity would be assigned a disproportionate share of the regulation burden in an incremental scheme9.

Using the marginal capacity cost of $63.62/kW-year provided by PSCO, the cost of the incremental regulation capacity necessitated by the addition of 10% or 15% wind generation ranges from $100,000 to $150,000 per year, or $0.052/MWH and $0.056/MWH of wind energy delivered respectively for each scenario.

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9 B. Kirby and E. Hirst, *Customer-Specific Metrics for The Regulation and Load-Following Ancillary Services*, , ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge TN, January, 2000

Table 10: Statistical Analysis Summary for Existing Load and Wind Data – Standard Deviation of Regulations Characteristics

Date	Standard Deviation of Regulation Characteristic [from 1 minute measurement values; in MW]							Difference due to Wind
	Load	No Mills	Total Wind	COGreen	Ponnequin	Peetz	Obligation Load w/ Wind	
2/1/2004	13.85	4.55	0.73	0.63	0.31	0.15	13.86	0.02
2/2/2004	15.86	13.58	1.28	1.00	0.43	0.21	15.91	0.05
2/3/2004	9.53	4.87	1.29	1.23	0.13	0.23	9.62	0.09
2/4/2004	15.19	5.11	1.34	1.30	0.15	0.19	15.25	0.06
2/5/2004	14.21	6.32	1.96	1.90	0.33	0.19	14.34	0.13
2/6/2004	12.35	5.53	0.49	0.15	0.40	0.23	12.36	0.01
2/7/2004	11.80	4.89	0.69	0.51	0.38	0.18	11.82	0.02
5/2/2004	13.88	4.58	1.71	0.90	1.37	0.42	13.98	0.10
5/3/2004	15.53	4.47	1.46	0.86	1.05	0.38	15.60	0.07
5/5/2004	22.34	16.64	1.75	1.59	0.54	0.35	22.41	0.07
5/5/2004	14.80	5.78	1.23	0.95	0.59	0.44	14.85	0.05
5/6/2004	9.04	4.29	1.35	1.08	0.69	0.36	9.14	0.10
5/7/2005	14.55	5.29	1.20	1.03	0.50	0.30	14.60	0.05
5/8/2004	15.75	4.53	1.49	1.34	0.37	0.37	15.82	0.07
8/1/2004	16.04	5.22	1.59	1.42	0.58	0.30	16.12	0.08
8/2/2004	16.08	5.15	2.02	1.89	0.56	0.42	16.21	0.13
8/3/2004	16.01	6.21	1.72	0.89	0.82	1.12	16.10	0.09
8/4/2004	25.32	20.57	1.85	1.71	0.48	0.45	25.38	0.07
8/5/2004	10.56	4.97	2.09	1.91	0.40	0.52	10.76	0.20
8/6/2004	17.74	5.08	1.38	1.07	0.66	0.48	17.80	0.05
8/7/2004	15.54	4.56	4.60	4.46	0.49	0.29	16.21	0.67
11/7/2004	15.26	4.47	0.52	0.48	0.15	0.13	15.27	0.01
11/8/2004	12.86	4.79	1.37	1.33	0.10	0.10	12.93	0.07
11/9/2004	14.44	5.18	1.71	1.60	0.26	0.29	14.55	0.10
11/10/2004	14.31	4.41	2.59	2.45	0.25	0.26	14.54	0.23
11/11/2004	15.48	5.07	1.12	1.08	0.20	0.14	15.52	0.04
11/12/2004	40.40	39.16	0.86	0.82	0.09	0.18	40.41	0.01
11/13/2004	17.13	4.46	0.65	0.56	0.17	0.21	17.14	0.01
Averages	**15.92**	**7.49**	**1.50**	**1.29**	**0.44**	**0.32**	**16.02**	**0.09**
Maximum	40.40	39.16	4.60	4.46	1.37	1.12	40.41	0.67
Minimum	9.04	4.29	0.49	0.15	0.09	0.10	9.14	0.01

Load Following Impacts

In real-time operations, generating resources must be adjusted to follow the control area demand as it rises in the early part of the day and declines in the evening and overnight. Wind generation is obviously not linked to any diurnal pattern of the load, and may alter the requirements for moving generation over short-periods within an hour and over intervals of one to several hours.

Statistical analysis of PSCO archived load data shows that 95% of the load changes over a ten-minute interval are less than +/- 117 MW. When wind generation corresponding to 10% of peak hourly load in 2007 is added to the control area, the 95% value for the ten minute deviations increases to 124 MW. At 15% wind generation, this grows to 131 MW (Figure 37).

The analysis which underlies these numbers is quite simple. Based on discussions with PSCO operators, these results were compared to an internal analysis of regulating reserve requirements based on data from the PI system and a more detailed (than the current study, anyway) mapping of actual Xcel-PSCO operational practice. The results reached with this method agreed relatively well with those from this study.

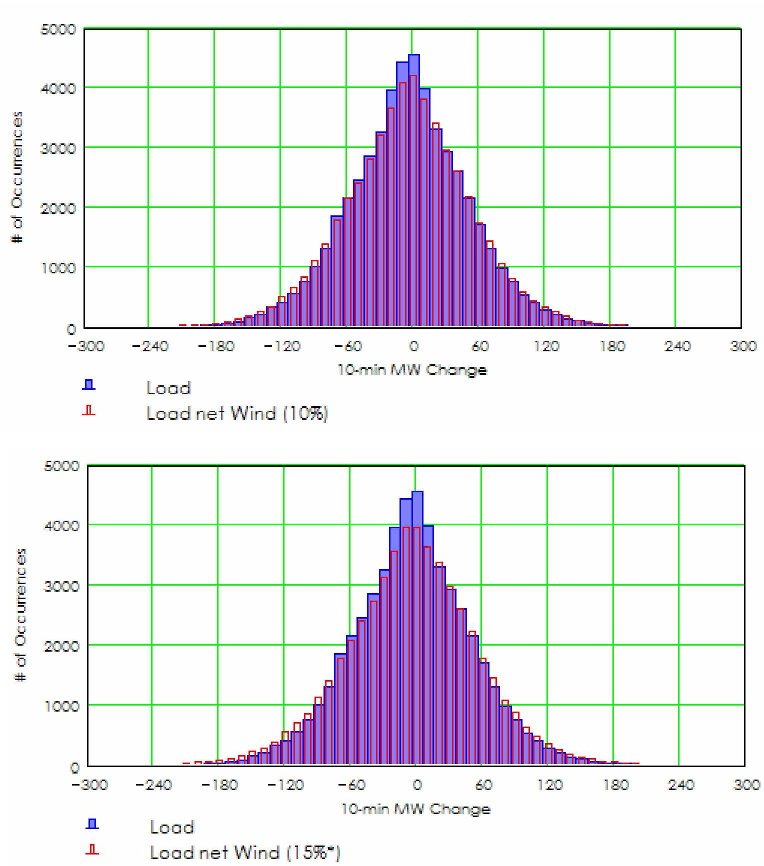


Figure 37: Deviations in control area demand at ten-minute intervals with and without wind generation.

The significant effect of the arc furnace load is also apparent in this time frame. Figure 38 shows the distribution of ten-minute load changes for the control area demand with and without the arc furnace loads. The standard deviation of the distribution for the obligation load is 68.5 MW. With the arc furnace removed, the standard deviation falls to 46 MW. The incremental effect of wind generation on ten-minute control area demand changes is substantially less at both the 10% and 15% levels than the single arc furnace load.

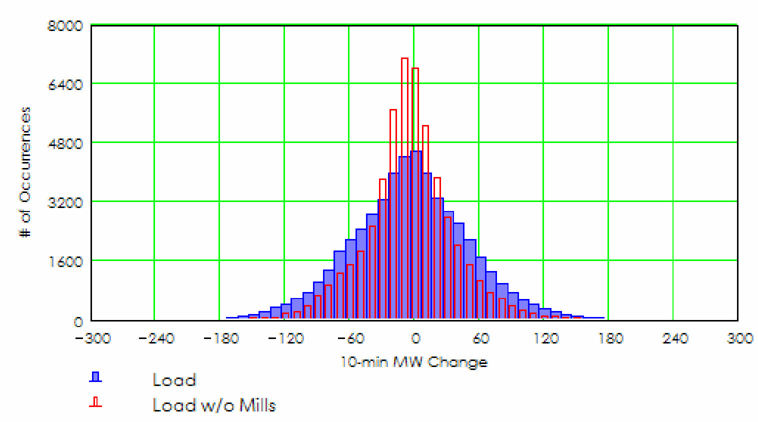


Figure 38: Ten-minute deviations of existing PSCO obligation load with and without arc furnace load.

In summary, the simple analysis of the wind and load data at ten minute intervals in this study provides important insight into how wind generation may affect real-time control. Based on the analysis, the effects are likely much less that would be experienced should the arc furnace load go from two 50 MW furnaces to a single 100 MW furnace. Regarding the furnaces, however, there is actually some predictability that is used to assist real-time operators. If the furnace is off, for example, the operators know that it can only go on to the 50 or 100 MW level. Conversely, and perhaps more importantly, if the furnace is full on, the operators incorporate the fact that the furnace load can only decline suddenly. This information may influence decisions to deploy additional regulating resources.

It is anticipated that the same level of comfort and adaptation with wind generation will be developed over some period of on the job training.

Distributions from all 52,700 or so intervals comprising the entire sample are shown in the following figures and summarized in Table 11, with distributions for each time frame shown in Figure 39 through Figure 42. The purpose of these statistical views is to illustrate the variability of the wind generation model for 10% over time frames of significance to real-time operators. While the primary concern is the variability and short-term uncertainty of the combination of wind and load, operators may view wind generation as an individual resource, and short-term forecasting systems in the near future will consider wind generation separate from load.

Table 11: Summary of 10-minute Wind Generation Changes from 10% Wind Model for CY2004

Generation change	10 min.	20 min	30 min.	40 min.
>- 400 MW	2	5	6	10
> -300 MW	12	23	31	41
> -200 MW	28	54	90	136
> -100 MW	91	235	506	974
> 100 MW	28	140	465	946
> 200 MW	4	10	19	41
> 300 MW	1	2	3	4
> 400 MW	1	2	3	4

.

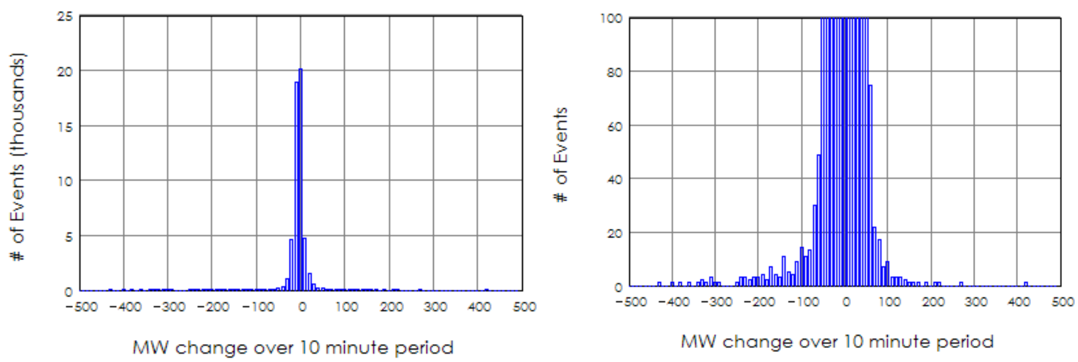


Figure 39: Distribution of 52,703 changes in wind generation over ten minute increments for 10% wind model, CY2004. Figure on right expands vertical scale.

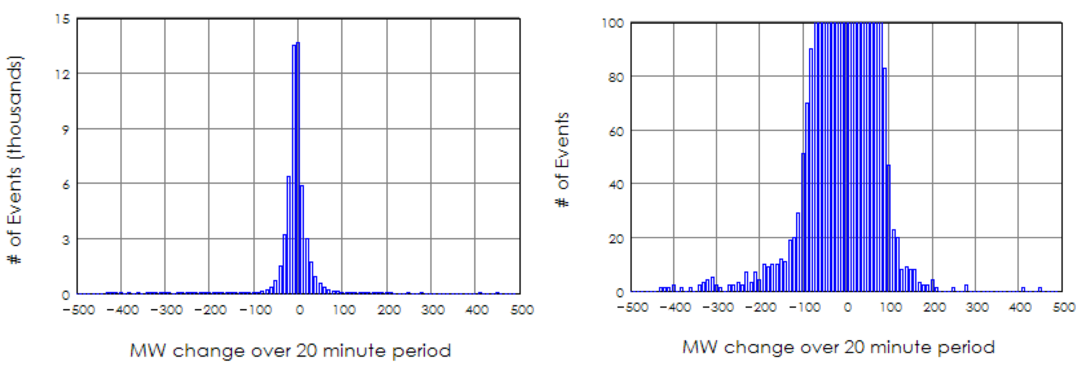


Figure 40: Distribution of 52,703 changes in wind generation over 20 minute increments for 10% wind model, CY2004. Figure on right expands vertical scale.

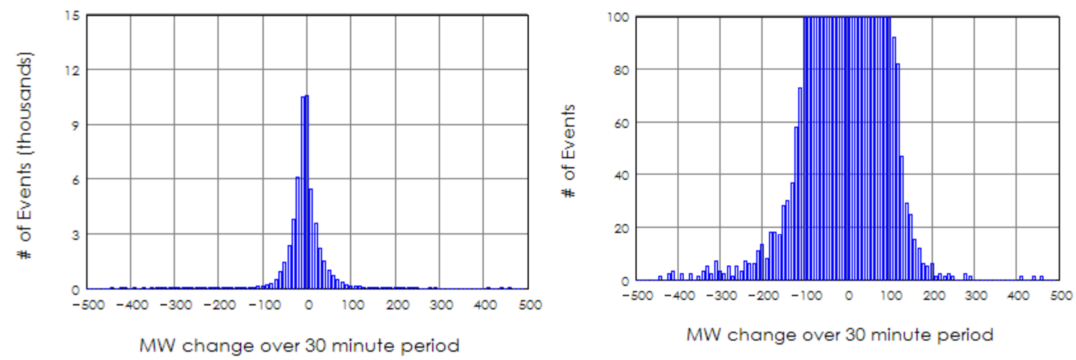


Figure 41: Distribution of 52,703 changes in wind generation over 30 minute increments for 10% wind model, CY2004. Figure on right expands vertical scale.

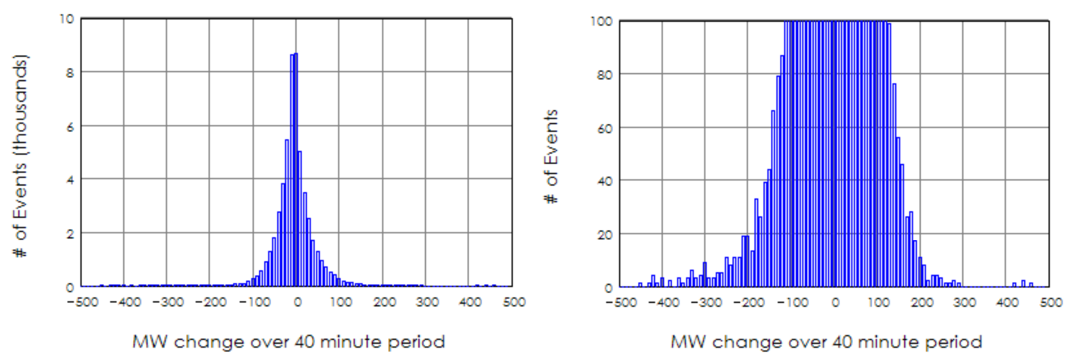


Figure 42: Distribution of 52,703 changes in wind generation over 40 minute increments for 10% wind model, CY2004. Figure on right expands vertical scale.

Day-Ahead and Hourly Impacts

The hourly cases were completed for at least one full year of data for three penetration levels of wind generation in the Phase I analysis: 10% (720 MW nameplate) and 15% (1080 MW nameplate). Wind generation data for the 10% and 15% cases was synthesized from the WindLogics MM5 meteorological simulation data for the historical year 2004 as per the detailed scenario definitions presented and discussed at previous technical review committee meetings.

Methodology

Wind generation integration cost is a function of the variability and uncertainty of energy delivery to the PSCO control area. Because wind generation can vary in an unfavorable pattern with respect to the system load, and can be predicted with only a certain degree of accuracy for forward periods for which optimum operating plans are constructed, additional cost can be incurred to serve the load not served by wind generation. The method used to calculate costs at the hourly level uses a series of comparative cases, and is designed to compare wind generation to a resource which does not possess those attributes that contribute to integration cost.

The analysis mimics the activities of PSCO generation schedulers and real time operators. An optimal plan is constructed based on hour-by-hour forecasts of the control area demand for the next day. Using this plan as a starting point, the day is simulated using actual rather than forecast control area demand.

In the reference case, wind generation is represented as an energy source that imposes no additional burden in terms of scheduling and real-time operations. This is taken to be an ideal energy source which is perfectly predictable and operates so as not to increase control area ramping or regulation requirements. In the reference case therefore, wind generation is represented as a flat block of energy for each day. The total energy for the day is exactly equal to what will be termed in the "actual" wind generation in later cases. This actual wind generation comes from the MM5 simulation data for the historical year.

With wind generation on the system, PSCO operators will use some type of next-day forecast of wind generation and load to construct the best plan for meeting the control area demand. Fuel for gas-fired generating units will also be purchased or "nominated" based on this plan. When the day arrives, both hourly load and wind generation will likely depart from the forecasts used to develop the optimal plan. The consequence is that actual operations over the day will likely be less than optimal (i.e. lowest cost) for the actual load and actual wind generation.

Integration cost in this study is defined as the difference between the actual production cost incurred to serve the net of actual load and actual wind generation and the production cost from the reference case, where wind is perfectly known and adds no variability to the control area, and where next-day load is the only uncertainty.

The method for determining the costs at the hourly level proceeds as follows:

1) Run the unit commitment program (ABB Couger) in "optimization" mode to develop a plan for serving the forecast load. Wind generation for the day is known perfectly, and is delivered in equal amounts each hour through the day.
    a) Save the unit commitment as the starting point for the next case.

b) Determine the hourly gas requirements and shape into an 8 am to 8 am "reference nomination".

2) Using the unit commitment from 1), re-run the day with forecast load replaced by actual load. Do not allow the program to re-optimize, but allow it to re-dispatch available units to meet the actual load. Manually commit generation to meet load that cannot be served from the previous day commitment.

   a) Save the total production cost for the period and define it as the "reference production cost"

   b) Calculate the hourly deviation in gas requirements from the reference nomination. These deviations must be accommodated by injection or withdrawal operations with system storage.

3) Repeat Step 1) with a next-day hour-by-hour wind generation forecast.

   a) Save the unit commitment as the starting point for the next case.

   b) Determine the hourly gas requirements, shape into a flat "actual nomination"

4) Using the unit commitment from 3), re-run the day with forecast load and forecast wind generation replaced by actual load and actual wind generation. Do not allow the program to re-optimize. Re-dispatch available units and manually commit off-line units to meet the control area demand.

   a) Save the total production cost for the period and define it as the "actual production cost".

   b) Calculate the hourly gas deviations from the "actual nomination"

Certain aspects of the methodology enumerated above merit additional emphasis:

- Load MWH and Wind MWH in "reference" and "actual" cases is identical. If wind generation is assumed to be a "must take" resource, the payment from PSCO to the wind generators is identical in both the "reference" and "actual" cases. Therefore, the cost per MWH of wind energy is not relevant to the analysis (i.e. it "subtracts out").
- Optimization cases are run only with next-day forecast data. All binding decisions (unit commitment or de-commitment, day-ahead purchases, etc.) must be carried forward to the simulation of the actual day.
- Simulation cases are run with actual hourly load and wind data, and start from the optimized day-ahead plan
- In the simulation cases, units are started manually (case is re-run) to cover "UNSERVED" energy. This action is a proxy for real-time operators, who on days where actual load significantly exceeds the day-ahead forecast, will have to procure more energy from available internal or external resources.

Finally, there is the issue of the wind generation attributes defined for the "reference" case. In this method, wind energy delivery is allowed to vary day-by-day, but the delivery within in a day is assumed to have the characteristics of a baseload resource. The argument for such treatment is that baseload resources impose no incremental burden on daily operations (save for decisions to de-commit large baseload resources). They neither assist with nor detract from the ramping or regulation requirements imposed by the load. In some respects, they are nearly invisible to the system operators.

The reference resource for wind assumed here is equivalent to an “as-available” energy contract with a third-party, where the terms of the contract allow the constant delivery to be scheduled a day in advance.

In some circumstances, defining the reference resource to be some type of conventional unit may be appropriate. Care must be taken, however, to operate this unit per the terms of the contract and within the capabilities of the actual proxy unit. As an example, if the reference resource were defined to be a simple cycle-gas turbine, it would not be appropriate to allow that unit to be dispatched to provide load following or other ancillary services unless the terms of the power purchase agreement were to explicitly include consideration of and compensation for this capability.

The project team feels that the characteristics of the reference resource as defined for this study are the most appropriate for an energy resource like wind generation.

Results

Results from application of the above method over an entire year of wind generation and system load data are documented in the following tables.

Table 12 and Table 13, document week-by-week the “all in” integration cost at the hourly level for wind generation penetrations of 10% and 15%. A couple of points of interest:

- The results exhibit significant variability on both a weekly and monthly basis. Significant monthly variation was evident in the previous study for the NSP system; results were not tabulated weekly in that study.
- The “negative” integration costs appear a little overstated when couched in terms of $/MWH of wind generation. If viewed in terms of total dollars, there are a few weeks where the production cost actually declines with wind, but the instance is not as striking when compared with production cost differentials for all the weeks expressed in dollars.

Table 12: Production Cost Differential Summary for 2007/2004 – 10% Wind Generation

				Reference		Actual		
Week Start	Load MWH	Wind MWH	Net MWH	Production Cost (k$)	Ave. $/MWH	Production Cost (k$)	Ave. $/MWH	Integration Cost
Thursday, Jan 1 2004	731,723	27,770	703,952	$ 21,088	$ 29.96	$ 21,099	$ 29.97	$0.39
Thursday, Jan 8 2004	709,014	23,973	685,041	$ 18,160	$ 26.51	$ 18,076	$ 26.39	($3.51)
Thursday, Jan 15 2004	713,743	27,770	685,972	$ 17,308	$ 25.23	$ 17,338	$ 25.28	$1.07
Thursday, Jan 22 2004	727,084	34,193	692,891	$ 17,549	$ 25.33	$ 17,621	$ 25.43	$2.08
Thursday, Jan 29 2004	724,817	32,216	692,602	$ 16,905	$ 24.41	$ 17,195	$ 24.83	$9.01
Thursday, Feb 5 2004	738,692	44,458	694,234	$ 16,740	$ 24.11	$ 16,753	$ 24.13	$0.29
Thursday, Feb 12 2004	715,488	24,342	691,146	$ 19,422	$ 28.10	$ 19,354	$ 28.00	($2.77)
Thursday, Feb 19 2004	688,683	37,161	651,521	$ 17,570	$ 26.97	$ 17,652	$ 27.09	$2.21
Thursday, Feb 26 2004	689,847	46,810	643,036	$ 16,427	$ 25.55	$ 16,396	$ 25.50	($0.66)
Thursday, Mar 4 2004	675,869	40,732	635,137	$ 14,727	$ 23.19	$ 14,933	$ 23.51	$5.05
Thursday, Mar 11 2004	661,850	47,051	614,800	$ 13,480	$ 21.93	$ 13,514	$ 21.98	$0.72
Thursday, Mar 18 2004	648,668	35,401	613,267	$ 13,454	$ 21.94	$ 14,043	$ 22.90	$16.65
Thursday, Mar 25 2004	653,043	34,162	618,880	$ 14,825	$ 23.95	$ 14,907	$ 24.09	$2.40
Thursday, Apr 1 2004	657,300	33,236	624,064	$ 15,050	$ 24.12	$ 15,148	$ 24.27	$2.94
Thursday, Apr 8 2004	661,482	27,244	634,238	$ 14,147	$ 22.31	$ 13,958	$ 22.01	($6.94)
Thursday, Apr 15 2004	654,011	51,228	602,782	$ 12,004	$ 19.91	$ 12,105	$ 20.08	$1.98
Thursday, Apr 22 2004	658,554	35,216	623,338	$ 12,883	$ 20.67	$ 13,239	$ 21.24	$10.12
Thursday, Apr 29 2004	663,578	29,848	633,730	$ 13,571	$ 21.41	$ 13,403	$ 21.15	($5.60)
Thursday, May 6 2004	686,175	45,741	640,435	$ 13,720	$ 21.42	$ 13,936	$ 21.76	$4.73
Thursday, May 13 2004	656,473	38,541	617,932	$ 14,129	$ 22.87	$ 14,231	$ 23.03	$2.65
Thursday, May 20 2004	666,624	43,667	622,957	$ 14,833	$ 23.81	$ 15,026	$ 24.12	$4.42
Thursday, May 27 2004	653,020	38,307	614,714	$ 13,536	$ 22.02	$ 13,750	$ 22.37	$5.58
Thursday, Jun 3 2004	731,345	45,761	685,584	$ 16,648	$ 24.28	$ 16,835	$ 24.56	$4.08
Thursday, Jun 10 2004	688,554	36,672	651,882	$ 15,955	$ 24.48	$ 16,131	$ 24.74	$4.79
Thursday, Jun 17 2004	632,048	30,633	601,415	$ 13,466	$ 22.39	$ 13,299	$ 22.11	($5.44)
Thursday, Jun 24 2004	661,795	28,063	633,733	$ 15,105	$ 23.83	$ 14,766	$ 23.30	($12.06)
Thursday, Jul 1 2004	691,554	23,799	667,755	$ 14,659	$ 21.95	$ 14,806	$ 22.17	$6.17
Thursday, Jul 8 2004	823,291	32,369	790,921	$ 19,528	$ 24.69	$ 19,829	$ 25.07	$9.30
Thursday, Jul 15 2004	776,341	23,808	752,533	$ 20,035	$ 26.62	$ 19,838	$ 26.36	($8.27)
Thursday, Jul 22 2004	684,358	29,581	654,777	$ 17,402	$ 26.58	$ 17,424	$ 26.61	$0.75
Thursday, Jul 29 2004	769,525	28,610	740,915	$ 20,568	$ 27.76	$ 20,499	$ 27.67	($2.41)
Thursday, Aug 5 2004	737,351	29,348	708,003	$ 17,775	$ 25.11	$ 17,889	$ 25.27	$3.88
Thursday, Aug 12 2004	728,204	32,367	695,838	$ 15,468	$ 22.23	$ 15,579	$ 22.39	$3.41
Thursday, Aug 19 2004	683,972	27,418	656,554	$ 15,132	$ 23.05	$ 15,025	$ 22.88	($3.90)
Thursday, Aug 26 2004	693,194	28,234	664,960	$ 14,427	$ 21.70	$ 14,324	$ 21.54	($3.64)
Thursday, Sep 2 2004	686,396	44,399	641,997	$ 13,636	$ 21.24	$ 13,875	$ 21.61	$5.38
Thursday, Sep 9 2004	710,406	39,197	671,209	$ 15,333	$ 22.84	$ 15,611	$ 23.26	$7.07
Thursday, Sep 16 2004	695,837	57,977	637,860	$ 14,445	$ 22.65	$ 14,663	$ 22.99	$3.76
Thursday, Sep 23 2004	652,544	36,353	616,191	$ 14,397	$ 23.36	$ 14,571	$ 23.65	$4.79
Thursday, Sep 30 2004	643,549	36,497	607,053	$ 13,572	$ 22.36	$ 13,661	$ 22.50	$2.43
Thursday, Oct 7 2004	651,067	35,088	615,979	$ 15,255	$ 24.77	$ 15,169	$ 24.63	($2.46)
Thursday, Oct 14 2004	653,802	40,657	613,145	$ 13,859	$ 22.60	$ 13,871	$ 22.62	$0.29
Thursday, Oct 21 2004	666,247	50,240	616,007	$ 14,396	$ 23.37	$ 14,548	$ 23.62	$3.02
Thursday, Oct 28 2004	689,007	55,281	633,726	$ 17,081	$ 26.95	$ 17,016	$ 26.85	($1.18)
Thursday, Nov 4 2004	679,505	49,788	629,717	$ 16,652	$ 26.44	$ 17,030	$ 27.04	$7.60
Thursday, Nov 11 2004	697,533	29,484	668,049	$ 17,157	$ 25.68	$ 17,129	$ 25.64	($0.97)
Thursday, Nov 18 2004	714,902	26,786	688,116	$ 18,921	$ 27.50	$ 18,838	$ 27.38	($3.11)
Thursday, Nov 25 2004	727,307	48,786	678,521	$ 15,730	$ 23.18	$ 15,920	$ 23.46	$3.91
Thursday, Dec 2 2004	757,582	32,466	725,117	$ 18,662	$ 25.74	$ 18,766	$ 25.88	$3.23
Thursday, Dec 9 2004	734,929	55,198	679,731	$ 16,458	$ 24.21	$ 16,549	$ 24.35	$1.65
Thursday, Dec 16 2004	761,499	44,669	716,830	$ 17,042	$ 23.77	$ 17,319	$ 24.16	$6.21
Thursday, Dec 23 2004	735,542	35,753	699,789	$ 16,480	$ 23.55	$ 16,648	$ 23.79	$4.70
Totals	36,194,924	1,914,346	34,280,578	826,772	$ 24.12	831,106	$ 24.24	$2.26

Table 13: Production Cost Differential Summary for 2007/2004 – 15% Wind Penetration

Week Start	Load MWH	Wind MWH	Net MWH	Reference Production Cost (k$)	Reference Ave. $/MWH	Actual Production Cost (k$)	Actual Ave. $/MWH	Integration Cost
Thursday, Jan 1 2004	731,170	39,438	691,731	$ 20,457	$ 29.57	$ 20,554	$ 29.71	$2.46
Thursday, Jan 8 2004	709,244	35,927	673,318	$ 17,301	$ 25.70	$ 17,454	$ 25.92	$4.23
Thursday, Jan 15 2004	713,743	39,438	674,304	$ 16,905	$ 25.07	$ 17,039	$ 25.27	$3.40
Thursday, Jan 22 2004	726,250	49,608	676,642	$ 16,635	$ 24.58	$ 16,962	$ 25.07	$6.59
Thursday, Jan 29 2004	724,803	42,395	682,408	$ 16,395	$ 24.03	$ 16,728	$ 24.51	$7.85
Thursday, Feb 5 2004	738,692	61,675	677,016	$ 15,976	$ 23.60	$ 16,060	$ 23.72	$1.36
Thursday, Feb 12 2004	715,488	34,860	680,627	$ 18,598	$ 27.32	$ 19,203	$ 28.21	$17.37
Thursday, Feb 19 2004	688,683	53,728	634,955	$ 16,687	$ 26.28	$ 16,917	$ 26.64	$4.29
Thursday, Feb 26 2004	689,779	65,238	624,541	$ 15,706	$ 25.15	$ 15,613	$ 25.00	($1.43)
Thursday, Mar 4 2004	675,869	59,312	616,557	$ 14,053	$ 22.79	$ 14,670	$ 23.79	$10.39
Thursday, Mar 11 2004	661,850	67,321	594,529	$ 12,491	$ 21.01	$ 13,056	$ 21.96	$8.39
Thursday, Mar 18 2004	648,668	49,494	599,174	$ 13,163	$ 21.97	$ 13,537	$ 22.59	$7.55
Thursday, Mar 25 2004	653,043	50,730	602,313	$ 14,255	$ 23.67	$ 14,398	$ 23.90	$2.81
Thursday, Apr 1 2004	657,299	47,213	610,086	$ 14,457	$ 23.70	$ 14,665	$ 24.04	$4.42
Thursday, Apr 8 2004	661,481	37,139	624,342	$ 13,704	$ 21.95	$ 13,477	$ 21.59	($6.12)
Thursday, Apr 15 2004	654,011	72,634	581,377	$ 11,262	$ 19.37	$ 11,796	$ 20.29	$7.35
Thursday, Apr 22 2004	658,554	49,269	609,284	$ 12,563	$ 20.62	$ 12,648	$ 20.76	$1.74
Thursday, Apr 29 2004	663,578	41,517	622,061	$ 13,130	$ 21.11	$ 13,140	$ 21.12	$0.24
Thursday, May 6 2004	686,176	62,485	623,691	$ 13,110	$ 21.02	$ 13,486	$ 21.62	$6.01
Thursday, May 13 2004	656,759	52,204	604,555	$ 13,696	$ 22.65	$ 13,797	$ 22.82	$1.94
Thursday, May 20 2004	666,624	58,081	608,543	$ 14,257	$ 23.43	$ 14,511	$ 23.85	$4.38
Thursday, May 27 2004	653,020	53,648	599,372	$ 12,776	$ 21.32	$ 13,350	$ 22.27	$10.71
Thursday, Jun 3 2004	731,345	64,891	666,454	$ 15,882	$ 23.83	$ 16,020	$ 24.04	$2.12
Thursday, Jun 10 2004	688,809	49,846	638,962	$ 15,306	$ 23.95	$ 15,538	$ 24.32	$4.65
Thursday, Jun 17 2004	630,749	40,669	590,080	$ 12,964	$ 21.97	$ 13,086	$ 22.18	$3.01
Thursday, Jun 24 2004	661,795	40,217	621,578	$ 14,318	$ 23.03	$ 14,285	$ 22.98	($0.82)
Thursday, Jul 1 2004	691,554	32,588	658,966	$ 14,335	$ 21.75	$ 14,290	$ 21.69	($1.39)
Thursday, Jul 8 2004	823,132	43,264	779,868	$ 19,180	$ 24.59	$ 19,309	$ 24.76	$2.98
Thursday, Jul 15 2004	776,341	34,208	742,133	$ 19,540	$ 26.33	$ 19,507	$ 26.29	($0.96)
Thursday, Jul 22 2004	684,483	42,871	641,612	$ 16,791	$ 26.17	$ 17,244	$ 26.88	$10.56
Thursday, Jul 29 2004	769,525	39,365	730,161	$ 19,955	$ 27.33	$ 19,977	$ 27.36	$0.57
Thursday, Aug 5 2004	735,999	42,710	693,290	$ 17,699	$ 25.53	$ 17,232	$ 24.86	($10.93)
Thursday, Aug 12 2004	728,204	47,299	680,905	$ 14,837	$ 21.79	$ 14,975	$ 21.99	$2.93
Thursday, Aug 19 2004	683,619	38,696	644,922	$ 14,476	$ 22.45	$ 14,592	$ 22.63	$2.98
Thursday, Aug 26 2004	693,194	39,914	653,281	$ 14,013	$ 21.45	$ 14,115	$ 21.61	$2.55
Thursday, Sep 2 2004	686,396	60,539	625,857	$ 13,145	$ 21.00	$ 13,336	$ 21.31	$3.15
Thursday, Sep 9 2004	710,456	52,501	657,955	$ 14,960	$ 22.74	$ 15,695	$ 23.85	$14.00
Thursday, Sep 16 2004	695,837	79,361	616,476	$ 13,760	$ 22.32	$ 14,225	$ 23.07	$5.86
Thursday, Sep 23 2004	650,686	51,856	598,830	$ 13,758	$ 22.98	$ 13,968	$ 23.33	$4.05
Thursday, Sep 30 2004	642,241	50,533	591,708	$ 13,006	$ 21.98	$ 13,226	$ 22.35	$4.35
Thursday, Oct 7 2004	651,067	51,139	599,928	$ 14,631	$ 24.39	$ 14,714	$ 24.53	$1.62
Thursday, Oct 14 2004	653,802	55,370	598,432	$ 13,085	$ 21.87	$ 13,141	$ 21.96	$0.99
Thursday, Oct 21 2004	665,947	69,340	596,607	$ 13,731	$ 23.01	$ 13,808	$ 23.14	$1.12
Thursday, Oct 28 2004	689,007	76,080	612,928	$ 16,512	$ 26.94	$ 16,038	$ 26.17	($6.23)
Thursday, Nov 4 2004	679,505	68,289	611,216	$ 15,841	$ 25.92	$ 15,851	$ 25.93	$0.14
Thursday, Nov 11 2004	697,785	41,253	656,532	$ 16,747	$ 25.51	$ 16,681	$ 25.41	($1.59)
Thursday, Nov 18 2004	714,902	36,728	678,174	$ 18,268	$ 26.94	$ 18,340	$ 27.04	$1.97
Thursday, Nov 25 2004	727,216	68,401	658,815	$ 15,280	$ 23.19	$ 15,315	$ 23.25	$0.51
Thursday, Dec 2 2004	757,582	46,631	710,952	$ 17,948	$ 25.25	$ 18,001	$ 25.32	$1.13
Thursday, Dec 9 2004	734,929	78,839	656,090	$ 15,239	$ 23.23	$ 15,804	$ 24.09	$7.17
Thursday, Dec 16 2004	761,502	63,725	697,777	$ 16,246	$ 23.28	$ 16,391	$ 23.49	$2.28
Thursday, Dec 23 2004	735,542	51,885	683,657	$ 15,747	$ 23.03	$ 15,909	$ 23.27	$3.12
Totals	36,187,935	2,682,363	33,505,572	794,777	$ 23.72	803,673	$ 23.99	$3.32

Wind Impacts on Gas Supply - Analysis and Results

Background

The gas supply system is one of the key components for providing the swing flexibility on the electric system. The gas system must stand ready to supply or absorb gas supply to the various generation facilities that are used to ramp up and down to balance the electric system needs. The minute-to-minute, hourly and daily flexibility of the gas system is generally provided through gas storage in the form of injections and withdrawals. In studying the impact of wind on the PSCo system, it is imperative to include the effects on the gas system and to include an identification of the resources that are necessary to provide this system flexibility.

Gas storage provides some intra-day flexibility, but the volume of storage is actually limited. Projected gas needs for the next day must be procured through market purchases with a lead time of 24 hours. These “nominations” are for the period 8 am on the operating day through 8 am of the following day, and are made prior to 8 am on the day prior to the operating day.

How the uncertainty of the wind energy to be delivered the next day affects the gas nomination process is the major question here. These impacts would manifest themselves as short-term gas injection or withdrawal requirements that are beyond the capability of the PSCO gas supply system.

Quantifying Impacts

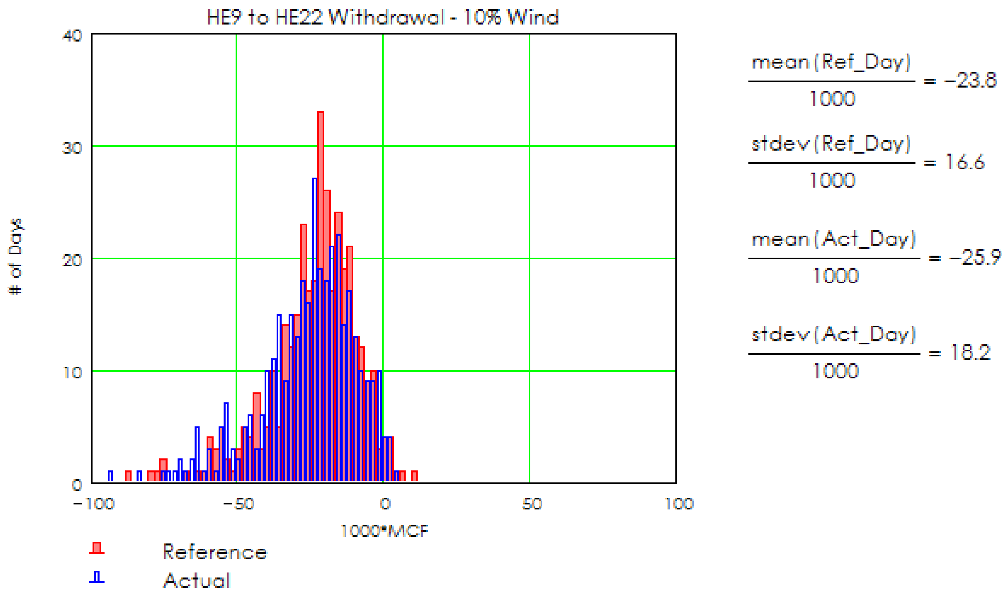
Extensive discussions were held with PSCO personnel to define methods for quantifying the impacts of wind generation on the gas supply system and nominating process. The statistical distributions shown in Figure 43 and Figure 44 are one result of those discussions.

In the hourly analysis, the gas nomination process was simulated as follows:

1. Based on next-day forecasts of hour-by-hour load and wind generation, the projected gas needs for electric generation determined by the ABB Couger program in the optimization step.
2. To reflect how gas is actually delivered to PSCO, the total forecast gas requirements for the next day are “shaped” into a flat profile for the 24 hour period.
3. The actual gas “burn” is determined from the re-dispatch of generation against the actual load and wind energy for the day.
4. The hour-by-hour gas needs from the re-dispatch are compared to the flat profile representing the daily nomination; hourly needs in excess of the profile become withdrawal periods and those smaller than the profile represent injections.
5. Injection/withdrawal requirements from the base case are compare to those from the reference case (defined earlier), where wind energy delivery is perfectly certain and does not vary through the day. In the reference case, the day-ahead uncertainty is due to load forecast error.

Figure 43 and Figure 44 illustrate the effect of wind generation on the daily injection and withdrawal for each day of the study year. The daytime withdrawal is defined to be the difference between the actual gas usage and the nomination for the day for hours ending 9 through 22. The nighttime injection is defined similarly for the period beginning at 10:00 pm and running to 8:00 am the following morning.

The distributions on each chart represent the case where wind energy for the day is known precisely (i.e. the “reference” case) and only the hourly load is uncertain, and the case where both wind and load are uncertain (the “actual” case). For the “actual” cases, gas nominations are computed by taking the average of the daily forecast gas needs for electric generation from the optimization based on load forecast and wind generation forecast. A similar procedure is used for the reference case, except that wind is assumed to be known perfectly in both the optimization and simulation runs.



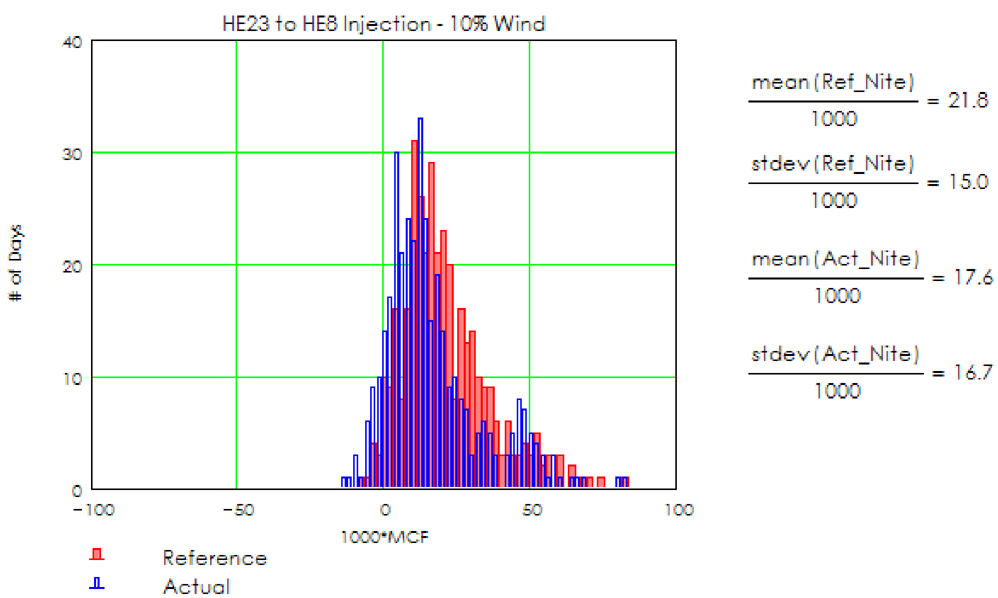
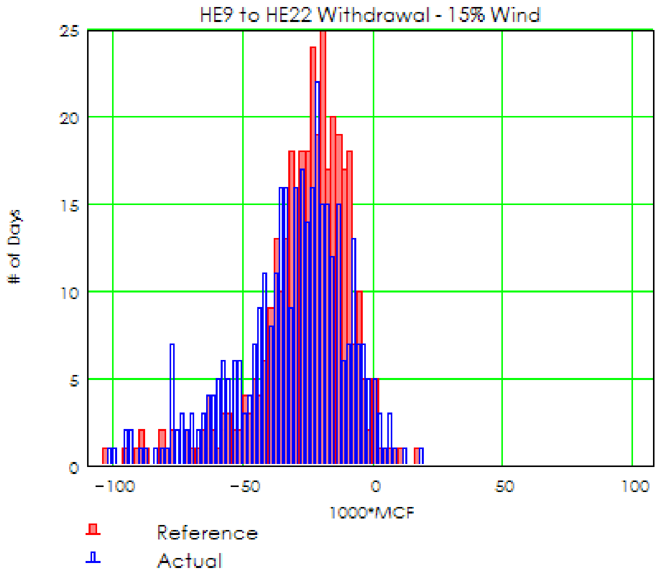


Figure 43: Effect of wind generation variability and uncertainty on deviations from day-ahead nominations during daytime and overnight for 10% wind penetration. (note: HE9 to HE22 = 8am to 10 pm)

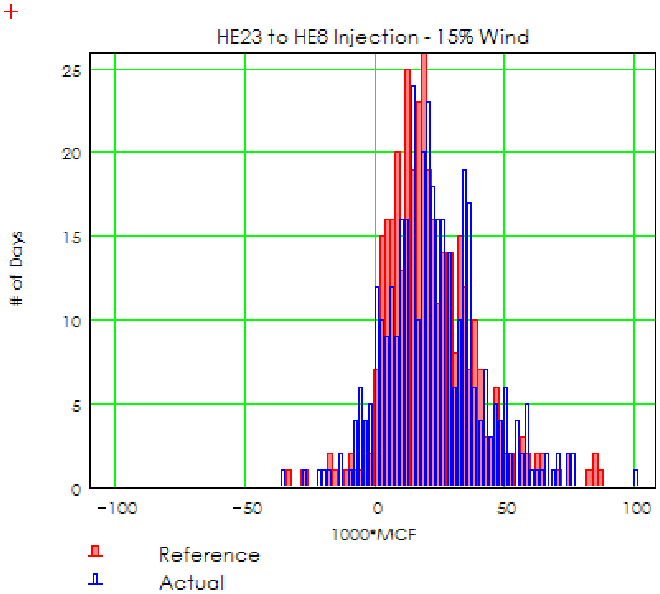


$$\frac{\text{mean}(\text{Ref\_Day})}{1000} = -26.2$$

$$\frac{\text{stdev}(\text{Ref\_Day})}{1000} = 18.2$$

$$\frac{\text{mean}(\text{Act\_Day})}{1000} = -31.2$$

$$\frac{\text{stdev}(\text{Act\_Day})}{1000} = 21.8$$



$$\frac{\text{mean}(\text{Ref\_Nite})}{1000} = 21.6$$

$$\frac{\text{stdev}(\text{Ref\_Nite})}{1000} = 17.1$$

$$\frac{\text{mean}(\text{Act\_Nite})}{1000} = 23.3$$

$$\frac{\text{stdev}(\text{Act\_Nite})}{1000} = 18.5$$

Figure 44: Effect of wind generation variability and uncertainty on deviations from day-ahead nominations during daytime and overnight for 10% wind penetration.

The hourly gas deviation distributions from the existing cases for 10% and 15% wind generation penetration cases are found in Figure 45 and Figure 46.

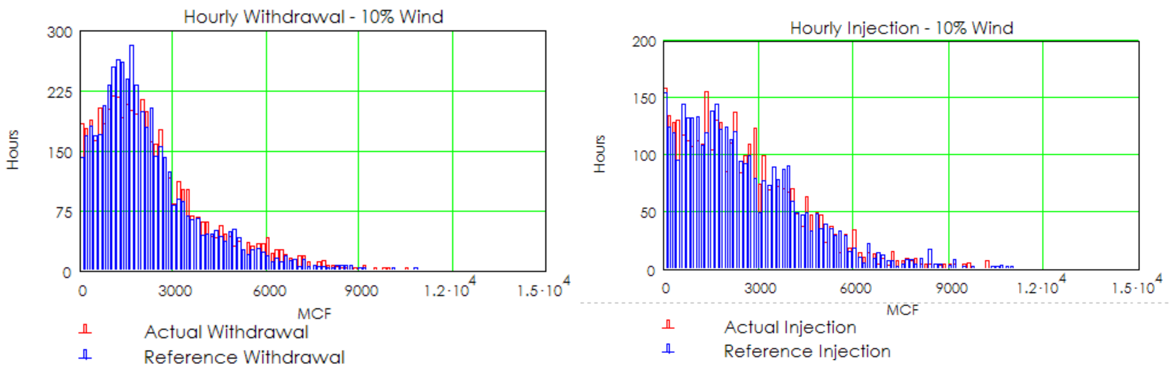


Figure 45: Distribution of hourly injections and withdrawals for actual and reference cases; 10% wind penetration.

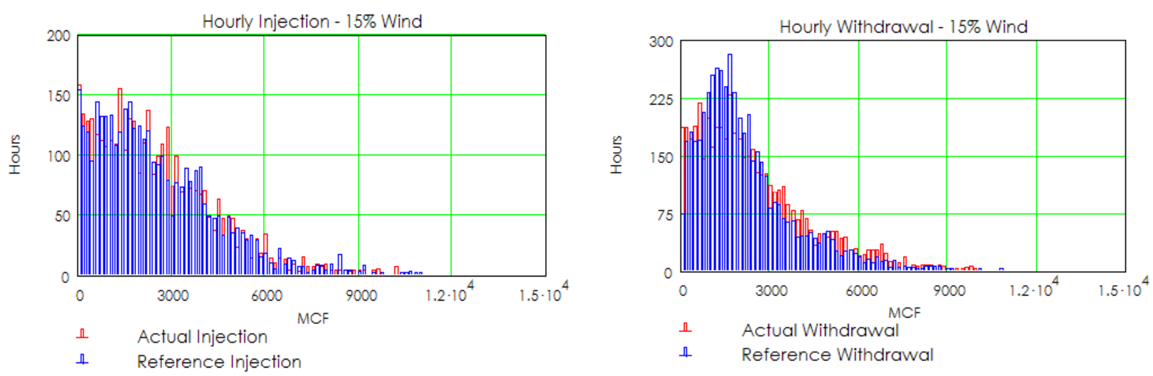


Figure 46: Distribution of hourly injections and withdrawals for actual and reference cases; 15% wind penetration.

Natural Gas Injection and Withdrawal Analysis Method

The gas data generated from the EnerNex modeling runs was sorted and the largest 5 hours of gas injection and withdrawal were found and averaged for actual injection, and withdrawal and the reference injection and withdrawal. To determine the resources necessary for the gas system to accommodate the additional flexibility that will be required by the wind on the PSCO electric system, a comparison of reference injection to actual injection and the reference withdrawal to actual withdrawal is made. This difference, actual case to the reference case, on an hourly basis is assumed to be the hourly gas storage requirements (injection and withdrawal capacity) that will be needed by the system. The hourly injection and withdrawal requirements are converted into typical gas transportation contractual terms by multiplying the hourly data by 24 hours to get a daily injection and withdrawal rate. The daily injection and withdrawal rates were then used in the financial analysis presented below.

Financial Analysis of the Injection and Withdrawal Wind Impacts

The daily injection and withdrawal requirements for wind are priced for this analysis by using the average unit cost of storage and transportation of new gas storage projects that are being developed in the Colorado area. The fuel for storage injection is calculated by taking the hourly wind injection impact and multiplying by an assumed number of injection hours in the year (2920 hrs) times the fuel percentage for the storage field. This is then multiplied by the average cost of gas and added to the injection annual cost.

The natural gas fuel supplied to the electric power plants for the Public Service (PSCO) customers is currently delivered through 2 main pipeline systems to the Colorado Front Range. Colorado Interstate Gas (CIG) provides transportation service to the power plants that are directly connected to CIG and to the PSCO gas distribution system. The PSCO system is also directly connected to a major natural gas marketing hub at Cheyenne Wyoming and transports gas to the power plants.

The current balancing of the existing gas fired electric generation is done using the 3 gas storage assets as described below:

- Through the PSCO gas distribution system based upon its contract with CIG for No Notice Storage and Transport Service (NNT).
- Through the CIG interstate system utilizing the connection to Young Gas Storage.
- Through the PSCO gas distribution system utilizing the Roundup gas storage system.

These three storage assets are used to provide the swing of gas flow needed on an hourly basis for PSCO's gas fired electric generation.

The CIG NNT service is the most flexible asset available to the Company and provides the majority of the hourly swing. These contracts primary use are to meet the PSCO gas distribution customer's needs but are available to the electric plants on an interruptible basis. CIG's NNT service is fully subscribed at this time and the availability of interruptible swing flexibility is decreasing as the need of the gas distribution system is growing. As a result, the electric swing requirements for the immediate future will most likely be satisfied by new storage facilities capable of very flexible intraday injection and withdrawal changes.

Future Storage Project

Due to the fact that the impacts of expanded wind must be met with a new gas storage projects, PSCO is prosing to use the information recently made available for the Windy Hill storage project, located 6 miles east of Brush Colorado. The cost of this storage service is quoted as $2.59 per deca-therm (Dth) of storage capacity. The quoted service price provides 0.0667 Dth of withdrawal capacity and 0.0225 Dth of injection capacity per Dth of storage capacity purchased. Injection fuel is estimated at 1.5% of the injected volume. Access from the proposed storage field to many of the large gas fired plants will require a significant investment for new pipeline construction.

Benefits of Gas Storage

The use of gas storage to meet the wind swing needs has a benefit on the price and hedging of the purchased natural gas. Because the storage asset can be filed during the summer and the drawn on during the winter to there is a winter / summer arbitrage benefit that will be credited to the gas purchase. The winter summer arbitrage is estimated from the futures market to be approximately $0.75 Dth. Since the price of the gas in the storage field is known there is no need financially hedge the market price of the gas with a call option. The average price of an at the market call option is currently $1.00 Dth. Since it is not possible to get storage 100% full these are applied to 95% of the storage volume and given as a credit to the impacts of the wind on the system.

Analysis and Conclusions

The overall impact of wind energy on the gas delivery system (based on the peak requirements) is determined by summing the costs of the needed storage and pipeline services and then dividing those costs by the annual megawatt hours of wind energy $/MWH. The cost of the gas storage required to meet the wind swing is partially offset by the benefits gas storage brings to the purchase of natural gas. The benefits of the gas storage are then subtracted from the wind impacts to get a final wind impact on the gas portfolio. Gas supply system impacts for the three wind generation scenarios are summarized in Table 14.

Table 14: Estimated Financial Impacts on PSCO Gas Supply due to Wind Generation Variability and Uncertainty.

Wind Penetration	10%	15%
$/ MWH Gas Impact No Storage Benefits	$2.17	$2.52
$ / MWH Gas Impact With Storage Benefits	$1.26	$1.45

The wind impact gas cost analysis is an incremental analysis that assumes the current electric generation has a base level of gas consumption deviations that the current gas service contracts meet. The incremental wind-caused gas deviation analysis assumes that the wind-caused deviations will not impact the underlying electric generation-caused gas consumption deviations. If the underlying gas consumption deviations are impacted by the incremental wind-caused gas consumption deviations there may be a need for additional resources not in the incremental analysis. The wind cost analysis is based the incremental service contracts or assets that are needed to accommodate the gas consumptions caused by the wind.

The costs of the gas consumption deviation caused by the wind are based on the storage services necessary to meet the wind-caused deviations. The storage services required for the 10% case increase dramatically for the 15% case but the cost impact per MWH of wind energy generated is fairly constant.

Summary and Analysis of Phase I Results

Conclusions, results, and comments from the previous chapters are summarized here.

Incremental Regulation Requirements

The statistical analysis found that the incremental regulation burden imposed by wind generation at the 10% and 15% penetration levels was quite small, and that the arc furnace load accounted for a significant share of the existing regulation burden.

The incremental regulation capacity necessary to maintain control performance at current levels was found to be 1.5 MW for 10% penetration and about 2.5 MW at 15%. Using a marginal capacity cost of $63/kW (provided by PSCO), the annual capacity cost of this incremental regulation capacity is $100,000 and $150,000 respectively, or about $0.052 to $0.056/MWH of wind energy.

PSCO's existing regulating burden is dominated by an arc furnace load, which reduces the incremental impact of wind generation. The capacity and cost numbers above are based on an incremental analysis, which depending on the perspective of the regulators or other policymakers, not necessary be the appropriate method for allocating the regulation burden amongst load, wind generation, and arc furnace.

Load Following and Intra-hourly Impacts

Statistical analysis of time-series wind generation data from the MM5 simulations and high-resolution load data from the PSCO EMS archives shows only a small impact of wind generation within the hour. Again, the arc furnace load dominates at this time scale.

No additional cost was assigned to wind generation as a result of this analysis, but concerns on the part of real-time operators remain. It should be remembered that in this realm, the experience and judgment of the real-time operators plays an important role, and can have both technical and economic consequences. While the arc furnace load is certainly problematic from a system control perspective, PSCO operators have developed significant experience with managing this load ("If the mill is on, it can only go off. If it is off, it may come on"). Wind generation, on the other hand, is mostly an unknown.

As experience is gained, it is likely that PSCO system operators would develop similar heuristics for managing the system with wind generation. Additionally, short-term wind generation forecasting (tens of minutes to a few hours ahead) is expected to provide information to operators that will enhance their decision-making processes for real-time operations. Given that the changes in wind generation from the chronological model developed for this study were shown to be no more significant and most of the time much smaller than those from the arc furnace load, the effect of wind generation within the hour and over periods of a couple to several hours should be limited.

Hourly Results

Table 1 summarizes the electric production and gas supply system costs from the hourly simulations and analysis. Note that these costs are not sensitive to the cost of or price paid for wind energy, as the construction of the comparative cases in the hourly analysis is such that this cost "subtracts out" in the differential production cost calculation.

Table 15: Summary of Hourly Results for Phase I Cases

Wind Penetration	Electric Production Cost Impact	Net Gas Supply System Impact	Total
10%	$2.25	$1.26	$3.51/MWH
15%	3.32	$1.45	$4.77/MWH

As expected, costs on both the electric and gas sides increase as the amount of wind generation increases. For the 10% and 15% cases, the increase is nearly linear. It has been postulated that the integration cost "curve" – integration cost plotted vs. wind generation capacity - for a particular power system is likely non-linear, in that there is a point where integration costs rise more quickly as the availability of low-cost options for managing wind generation are exhausted. Initial analysis of a 20% penetration case appeared to show this, but also generated significant questions about the sensitivity of integration costs to assumptions and key input data, such as wind generation forecasting accuracy. Analysis of this penetration level is ongoing and will be reported later.

Even at the lower penetration levels, the sensitivity of integration costs to the availability of certain flexible generation resources can be seen. A case where the Cabin Creek Pump Storage facility was taken out of service for the entire year was run for the 10% penetration level. Table 16 contains results for 52 weeks at 10% wind generation with the Cabin Creek pump storage facility out of service for the entire year. The increase in integration cost for this case illustrates, at least qualitatively, the value of Cabin Creek in helping the system operators manage wind generation. Electric production costs increased by over 50% at the 10% wind penetration level.

Gas-fired generation in PSCO's portfolio of resources also provides flexibility for managing wind. Simple-cycle gas turbines can be started relatively quickly and can be dispatched to compensate for changes in wind generation. Combined-cycle plants can also provide some flexibility, but configuration constraints and lower plant heat rates would likely result in them being significantly loaded during operation.

Table 16: Production Cost Differential Summary for 2007/2004 - 10% wind Generation, Cabin Creek on Outage for Entire Year

Week Start	Load MWH	Wind MWH	Net MWH	Reference Production Cost (k$)	Reference Ave. $/MWH	Actual Production Cost (k$)	Actual Ave. $/MWH	Integration Cost
Thursday, Jan 1 2004	730,501	27,770	702,731	$ 21,120	$ 30.05	$ 21,167	$ 30.12	$1.67
Thursday, Jan 8 2004	708,933	23,973	684,959	$ 18,546	$ 27.08	$ 18,317	$ 26.74	($9.52
Thursday, Jan 15 2004	713,743	27,770	685,972	$ 17,631	$ 25.70	$ 17,610	$ 25.67	($0.75
Thursday, Jan 22 2004	726,339	34,193	692,146	$ 17,867	$ 25.81	$ 17,990	$ 25.99	$3.61
Thursday, Jan 29 2004	724,818	32,216	692,603	$ 17,473	$ 25.23	$ 17,607	$ 25.42	$4.16
Thursday, Feb 5 2004	738,692	44,458	694,234	$ 17,472	$ 25.17	$ 17,514	$ 25.23	$0.96
Thursday, Feb 12 2004	715,488	24,342	691,146	$ 19,569	$ 28.31	$ 20,093	$ 29.07	$21.50
Thursday, Feb 19 2004	688,683	37,161	651,521	$ 17,907	$ 27.48	$ 18,015	$ 27.65	$2.91
Thursday, Feb 26 2004	689,304	46,810	642,493	$ 16,785	$ 26.13	$ 16,745	$ 26.06	($0.85
Thursday, Mar 4 2004	675,775	40,732	635,043	$ 15,412	$ 24.27	$ 15,582	$ 24.54	$4.17
Thursday, Mar 11 2004	661,850	47,051	614,800	$ 13,614	$ 22.14	$ 14,148	$ 23.01	$11.35
Thursday, Mar 18 2004	648,668	35,401	613,267	$ 14,201	$ 23.16	$ 14,374	$ 23.44	$4.89
Thursday, Mar 25 2004	653,030	34,162	618,868	$ 15,180	$ 24.53	$ 15,422	$ 24.92	$7.07
Thursday, Apr 1 2004	657,300	33,236	624,064	$ 15,309	$ 24.53	$ 15,473	$ 24.79	$4.93
Thursday, Apr 8 2004	661,482	27,244	634,238	$ 14,138	$ 22.29	$ 14,169	$ 22.34	$1.15
Thursday, Apr 15 2004	654,011	51,228	602,782	$ 12,373	$ 20.53	$ 12,449	$ 20.65	$1.48
Thursday, Apr 22 2004	658,554	35,216	623,338	$ 13,436	$ 21.56	$ 13,629	$ 21.86	$5.46
Thursday, Apr 29 2004	663,578	29,848	633,730	$ 13,680	$ 21.59	$ 13,854	$ 21.86	$5.82
Thursday, May 6 2004	686,175	45,741	640,434	$ 13,951	$ 21.78	$ 14,037	$ 21.92	$1.89
Thursday, May 13 2004	656,760	38,541	618,220	$ 14,242	$ 23.04	$ 14,614	$ 23.64	$9.67
Thursday, May 20 2004	666,624	43,667	622,957	$ 15,144	$ 24.31	$ 15,493	$ 24.87	$7.97
Thursday, May 27 2004	653,020	38,307	614,714	$ 13,833	$ 22.50	$ 14,049	$ 22.85	$5.63
Thursday, Jun 3 2004	731,298	45,761	685,537	$ 17,116	$ 24.97	$ 17,330	$ 25.28	$4.69
Thursday, Jun 10 2004	687,003	36,672	650,331	$ 16,115	$ 24.78	$ 16,066	$ 24.70	($1.33
Thursday, Jun 17 2004	632,475	30,633	601,842	$ 13,344	$ 22.17	$ 13,762	$ 22.87	$13.66
Thursday, Jun 24 2004	661,795	28,063	633,733	$ 15,088	$ 23.81	$ 15,368	$ 24.25	$9.98
Thursday, Jul 1 2004	691,505	23,799	667,706	$ 15,194	$ 22.76	$ 14,986	$ 22.44	($8.78
Thursday, Jul 8 2004	823,282	32,369	790,913	$ 20,145	$ 25.47	$ 20,157	$ 25.49	$0.37
Thursday, Jul 15 2004	776,341	23,808	752,533	$ 20,364	$ 27.06	$ 20,246	$ 26.90	($4.94
Thursday, Jul 22 2004	684,195	29,581	654,614	$ 17,807	$ 27.20	$ 17,709	$ 27.05	($3.32
Thursday, Jul 29 2004	769,412	28,610	740,802	$ 20,701	$ 27.94	$ 20,792	$ 28.07	$3.15
Thursday, Aug 5 2004	736,904	29,348	707,556	$ 18,326	$ 25.90	$ 18,451	$ 26.08	$4.27
Thursday, Aug 12 2004	728,204	32,367	695,838	$ 15,878	$ 22.82	$ 15,829	$ 22.75	($1.52
Thursday, Aug 19 2004	684,831	27,418	657,413	$ 15,207	$ 23.13	$ 15,333	$ 23.32	$4.63
Thursday, Aug 26 2004	693,194	28,234	664,960	$ 14,674	$ 22.07	$ 14,881	$ 22.38	$7.33
Thursday, Sep 2 2004	686,222	44,399	641,823	$ 14,033	$ 21.86	$ 14,295	$ 22.27	$5.89
Thursday, Sep 9 2004	709,190	39,197	669,992	$ 15,863	$ 23.68	$ 16,336	$ 24.38	$12.07
Thursday, Sep 16 2004	695,996	57,977	638,019	$ 14,946	$ 23.43	$ 15,202	$ 23.83	$4.41
Thursday, Sep 23 2004	651,385	36,353	615,032	$ 14,694	$ 23.89	$ 14,840	$ 24.13	$4.03
Thursday, Sep 30 2004	643,050	36,497	606,554	$ 13,912	$ 22.94	$ 14,141	$ 23.31	$6.29
Thursday, Oct 7 2004	651,066	35,088	615,978	$ 15,306	$ 24.85	$ 15,594	$ 25.32	$8.23
Thursday, Oct 14 2004	653,801	40,657	613,144	$ 14,140	$ 23.06	$ 14,142	$ 23.06	$0.04
Thursday, Oct 21 2004	666,047	50,240	615,807	$ 14,902	$ 24.20	$ 14,770	$ 23.98	($2.64
Thursday, Oct 28 2004	689,007	55,281	633,726	$ 17,233	$ 27.19	$ 17,379	$ 27.42	$2.63
Thursday, Nov 4 2004	679,505	49,788	629,717	$ 16,767	$ 26.63	$ 17,049	$ 27.07	$5.67
Thursday, Nov 11 2004	695,579	29,484	666,095	$ 17,267	$ 25.92	$ 17,189	$ 25.81	($2.67
Thursday, Nov 18 2004	714,902	26,786	688,116	$ 18,730	$ 27.22	$ 18,763	$ 27.27	$1.25
Thursday, Nov 25 2004	727,256	48,786	678,471	$ 16,070	$ 23.69	$ 16,310	$ 24.04	$4.93
Thursday, Dec 2 2004	757,582	32,466	725,117	$ 18,770	$ 25.89	$ 18,976	$ 26.17	$6.32
Thursday, Dec 9 2004	734,929	55,198	679,731	$ 16,735	$ 24.62	$ 16,822	$ 24.75	$1.59
Thursday, Dec 16 2004	761,290	44,669	716,620	$ 17,379	$ 24.25	$ 17,517	$ 24.44	$3.09
Thursday, Dec 23 2004	735,542	35,753	699,789	$ 16,914	$ 24.17	$ 16,787	$ 23.99	($3.56
Totals	36,186,114	1,914,346	34,271,768	842,502	$ 24.58	849,372	$ 24.78	$3.59

Phase II Analysis

A follow-on effort, designated as the "Phase II" portion of the study, was defined to address certain items from the Order and Stipulation not covered by the initial analysis. Those items include:

- *Determine whether ancillary costs vary by geographic region within the state (e.g. Northeast vs. Southeast corners) and how the size of a wind facility impacts ancillary costs.*
- *Determine whether ancillary costs remain nearly the same for different sized facilities within certain ranges. The Commission will not specify the range, but instead instructs PSCo to examine the data to determine if it is appropriate to assume different ancillary costs depending upon size and geographic region, instead of a system-wide figure.*
- *Goal – ability to determine ancillary costs on a project-by-project basis for accurate comparison of projects in future RFPs and future LCP dockets.*
- *The study should analyze the effect of contracted wind bidder projects on PSCo's system, because ancillary costs may vary significantly based on wind penetration level, geographic location, and diversity of wind resources, and these factors can not be fully considered until Renewable RFP projects are under contract.*

In discussions with PSCO, it was determined that the following tasks would be executed to address these remaining items from the order and stipulation:

- Analyze the wind generation models developed from the MM5 simulation data to determine if there is any significant difference in the "variability" of the wind resource and therefore wind energy production by major region within the state.
- Postulate a "maximum" variability scenario where wind generation is disproportioned allocated to a single region in the state; re-run the hourly analysis for the 15% penetration level to assess how integration costs compare to the base case for this level analyzed in Phase I.
- From existing knowledge and information, assess whether there would be any expected differences in next-day wind generation forecast accuracy between the four regions in the state.

Assessing Regional Variability

Wind generation in PSCO territory is allocated to one of four regions within the state:

1. North
2. East
3. Central
4. South (actually southeast)

For each region, variability statistics were computed for a collection of six proxy towers assigned to that region. That number was chosen as the sample size since there were only that many proxy towers located in the East region. It was assumed that a single 1.5 MW turbine was installed at each proxy tower locations in the sample. Hourly generation was computed for a three years sample of hourly data.

Change in wind generation from hour to hour was chosen as the metric to represent variability. For each region, an average hourly wind generation was calculated from the individual turbine/proxy tower locations. The standard deviation of the hour-to-hour differences was then computed.

Table 17: Standard Deviation of Hourly Variability by Region

Region	Hour Variability (% of rated)
North	10.9%
East	11.5%
Central	12.1%
Southeast	11.4%

Differences in the hour-by-hour variations between regions do not appear to be significant based on this relatively perfunctory analysis. The current understanding of drivers for wind integration costs makes locational extrapolation somewhat difficult. While is it is known that greater spatial and geographic diversity reduce wind generation variability and therefore the costs to manage, there has been little opportunity for the quantitative sensitivity analysis that would be necessary for extracting a meaningful metric for location-based variability affects.

Creating a "Maximum Variability" Scenario

While the variability of wind resource does not appear to vary much between regions, a wind generation scenario where development was concentrated in a single region (relative to the assumptions used in Phase I) could exhibit much more variability in the aggregate.

To assess how the integration costs would be affected by this type of development, a new scenario was created. The objective was to concentrate as much wind as possible in a single region (leaving existing capacity in its current location). The number and coverage of proxy towers in the MM5 model proved to be a limitation on how this could be done. To provide for valid comparison with the 15% base case, the assumed capacity per proxy tower could not be changed.

Figure 47 illustrates the scenario that was created to represent a concentrated wind generation development scenario with presumably more variability than the base case used in Phase I. In the figure, red dots represent proxy towers and wind generation that was present in the original 15% case but has been relocated in this scenario. Red flags represent unused locations. All other locations represent proxy towers used for this new scenario.

Table 18 summarizes the new scenario showing installed capacity by region. Generation in the Central region has been maximized since it contained the largest number of proxy towers. The increased capacity was drawn from the North and Southeast.

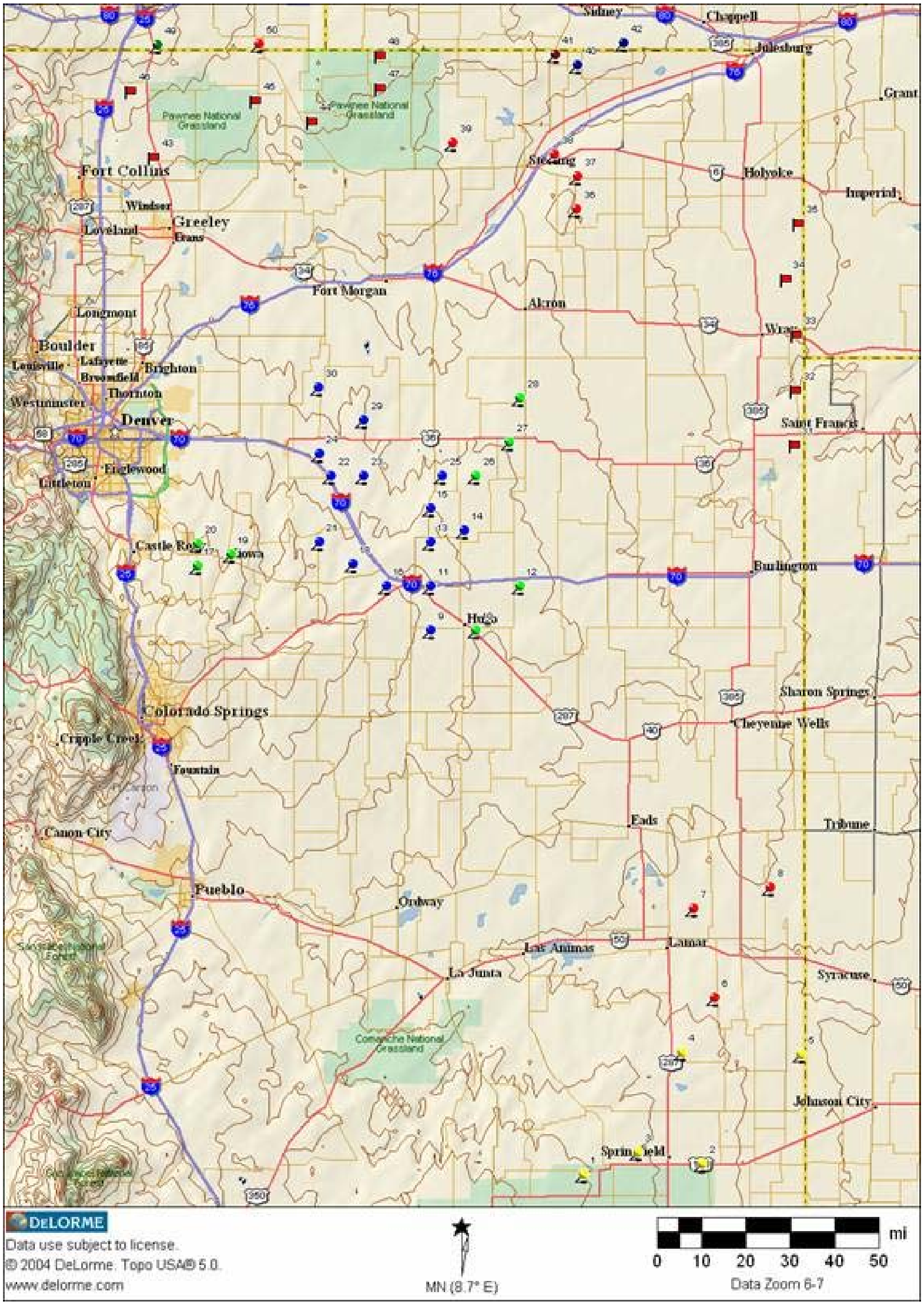


Figure 47: Proxy towers in "Maximum Variability" scenario.

Table 18: Re-allocation of Wind Generation from Original 15% Scenario to Maximize Variability

Region	Original Scenario (MW)	Modified Scenario (MW)
North	325	130
Southeast	257	162
Central	456	746
Total	**1038**	**1038**

Integration Costs for the "Maximum Variability" Scenario

The wind model described in the previous section was inserted into the identical frame work for the 15% penetration case from Phase I. Week-by-week results of the hourly analysis with the new wind model are shown in Table 19.

Integration cost from the hourly analysis with this wind model is slightly higher than the Phase I case for this penetration level. Since the only difference between the cases is the wind generation model, it is logical to assume that this difference can be attributed to increased variability.

Before drawing such a conclusion, however, there are some additional points to consider:

- There are a very large number of "moving parts" in this analysis. Previous attempts to find strong correlations between integration costs and input data or assumptions have been mostly unsuccessful.
- Test cases for the Phase I scenarios using load patterns and wind generation from a different historical year produced cost results near but not identical to what was found in the published cases. The nature of the analysis would lead to some expected statistical variations.
- There are significant non-linearities embedded in this problem. Bad combinations of load and wind generation forecast error, combined with unit forced or maintenance outages, for example, can be very costly. The approaches to resolving these severe situations used in the analysis for this study are likely different than what expert planners and operators at PSCO do, exacerbating the overall effect of these unique combinations of input data.

Table 19: Production Cost Impacts for 15% Penetration – Concentrated Development

Month	Week #	Reference Production Cost (k$)	Reference MWH	Reference Wind MWH	Reference $/MWH	"Actual" Production Cost (k$)	"Actual" MWH	"Actual" Wind MWH	"Actual" $/MWH	Integration Cost ($/MWH Wind)
Jan 1	1	$20,272	732,793	43,371	$27.66	$20,525	732,333	43,371	$28.03	$5.82
8	2	$17,458	709,691	32,819	$24.60	$17,670	709,574	32,819	$24.90	$6.45
15	3	$17,012	713,713	33,803	$23.84	$17,157	713,722	33,803	$24.04	$4.29
22	4	$17,003	727,956	47,247	$23.36	$16,965	727,173	47,247	$23.33	-$0.80
29	5	$16,702	724,809	40,044	$23.04	$16,948	724,184	40,044	$23.40	$6.16
Feb 5	6	$16,170	738,692	59,820	$21.89	$16,072	738,692	59,820	$21.76	-$1.63
12	7	$18,666	715,488	36,250	$26.09	$19,000	715,488	36,250	$26.56	$9.21
19	8	$16,642	688,683	55,698	$24.16	$16,711	688,683	55,698	$24.27	$1.24
25	9	$15,612	689,850	69,437	$22.63	$15,394	689,850	69,437	$22.31	-$3.14
Mar 4	10	$14,140	675,869	56,967	$20.92	$14,325	675,869	56,967	$21.19	$3.24
11	11	$12,449	661,850	68,728	$18.81	$13,057	661,850	68,728	$19.73	$8.85
19	12	$13,436	648,668	51,174	$20.71	$13,862	648,668	51,174	$21.37	$8.33
26	13	$14,074	653,036	52,847	$21.55	$14,289	653,043	52,847	$21.88	$4.07
Apr 1	14	$14,440	657,300	47,365	$21.97	$14,679	657,300	47,365	$22.33	$5.04
8	15	$13,418	661,482	37,032	$20.28	$13,428	661,481	37,032	$20.30	$0.28
15	16	$11,204	654,011	77,352	$17.13	$11,558	654,011	77,352	$17.67	$4.58
22	17	$12,494	658,554	49,253	$18.97	$12,770	658,554	49,253	$19.39	$5.60
29	18	$13,070	663,578	41,752	$19.70	$13,389	663,578	41,752	$20.18	$7.64
May 6	19	$13,206	686,175	63,444	$19.25	$14,116	686,176	63,444	$20.57	$14.35
13	20	$13,585	656,375	54,178	$20.70	$13,821	656,801	54,178	$21.04	$4.36
20	21	$14,451	666,624	58,444	$21.68	$14,828	666,624	58,444	$22.24	$6.45
27	22	$13,126	653,020	53,124	$20.10	$13,221	653,020	53,124	$20.25	$1.78
Jun 3	23	$16,309	731,345	64,959	$22.30	$17,407	730,550	64,959	$23.83	$16.90
10	24	$15,161	689,003	49,417	$22.00	$15,800	689,187	49,417	$22.93	$12.95
17	25	$13,025	632,454	37,713	$20.60	$13,320	634,043	37,713	$21.01	$7.81
24	26	$14,235	661,795	41,366	$21.51	$14,535	661,786	41,366	$21.96	$7.26
Jul 1	27	$14,355	691,554	32,206	$20.76	$14,568	691,554	32,206	$21.07	$6.62
8	28	$19,451	823,395	40,599	$23.62	$19,439	821,150	40,599	$23.67	-$0.31
15	29	$20,014	776,341	33,984	$25.78	$19,410	776,341	33,985	$25.00	-$17.78
22	30	$16,626	684,543	42,918	$24.29	$16,859	684,543	42,918	$24.63	$5.43
29	31	$20,073	769,525	39,805	$26.08	$19,936	769,525	39,805	$25.91	-$3.45
Aug 5	32	$17,111	735,635	44,970	$23.26	$17,588	737,351	44,970	$23.85	$10.60
12	33	$15,098	728,204	47,743	$20.73	$15,074	728,204	47,743	$20.70	-$0.50
19	34	$14,486	684,548	40,782	$21.16	$14,714	684,819	40,782	$21.49	$5.57
26	35	$14,039	693,194	39,508	$20.25	$14,107	693,194	39,508	$20.35	$1.72
Sep 2	36	$13,081	686,396	60,484	$19.06	$13,120	686,294	60,484	$19.12	$0.64
9	37	$14,918	710,456	52,719	$21.00	$15,414	710,455	52,719	$21.70	$9.40
16	38	$13,812	695,837	77,440	$19.85	$14,289	695,837	77,440	$20.53	$6.15
23	39	$13,699	650,033	53,371	$21.07	$14,133	649,531	53,371	$21.76	$8.13
30	40	$13,073	643,549	49,422	$20.31	$13,178	641,338	49,422	$20.55	$2.13
Oct 7	41	$14,545	651,067	52,301	$22.34	$14,768	651,067	52,301	$22.68	$4.27
14	42	$13,243	653,802	58,858	$20.26	$13,138	653,802	58,858	$20.10	-$1.78
21	43	$13,405	666,247	75,641	$20.12	$13,537	666,245	75,641	$20.32	$1.74
28	44	$16,020	689,007	76,100	$23.25	$16,152	689,007	76,100	$23.44	$1.73
Nov 4	45	$15,753	679,505	70,664	$23.18	$15,933	679,505	70,664	$23.45	$2.55
11	46	$16,637	698,733	42,834	$23.81	$16,715	698,737	42,834	$23.92	$1.82
18	47	$17,983	714,902	36,586	$25.15	$18,170	714,890	36,586	$25.42	$5.10
25	48	$15,497	727,117	65,030	$21.31	$15,293	726,543	65,030	$21.05	-$3.13
Dec 2	49	$18,048	757,582	44,686	$23.82	$18,098	757,582	44,686	$23.89	$1.10
9	50	$15,551	734,929	77,926	$21.16	$15,728	734,352	77,926	$21.42	$2.28
16	51	$16,263	761,502	62,165	$21.36	$16,679	761,502	62,165	$21.90	$6.69
23	52	$15,900	735,542	55,206	$21.62	$15,735	735,542	55,206	$21.39	-$2.99
		$796,040	**36,195,961**	**2,697,548**	**$21.99**	**$806,618**	**36,191,152**	**2,697,548**	**$22.29**	**$3.92**

Regional Wind Generation Forecasting Issues

Forecasts of wind generation are important in day-ahead planning and scheduling of generating resources and transactions. As with poor forecasts of system load during periods of hard-to-predict weather, significant deviations from forecast values can lead to more costly real-time dispatch decisions or short-term power sales or purchases.

The following analysis is a discussion of the challenges for forecasting hub height winds (and resultant power) in eastern Colorado in the day-ahead period. The assessments are founded on the fundamental knowledge of governing synoptic and mesoscale weather systems that control the meteorology of this region. This analysis does not represent a quantitative study, but rather, an assessment based on both the applicable meteorology and direct experience with forecasting the weather in eastern Colorado.

Forecasting winds (and resultant power) for the approximate eastern 40 percent of Colorado is highly dependent on getting the spatial distribution of pressure gradients correct. Based on first principals, it is the horizontal pressure gradient that drives the wind field, thus, getting the forecast pressure field correct is fundamental to achieving an accurate wind forecast. Note that day-ahead meteorological forecasts, and specifically day-ahead wind forecasts, are largely based on numerical weather prediction models of the atmosphere. The forecasts generated by these models are highly dependent upon the assimilation of meteorological observations used to initialize the model and model attributes such as the horizontal and vertical grid spacing and parameterization of physical processes.

The topography of eastern Colorado just downstream from the Rocky Mountains (from the perspective of generally westerly flow aloft) presents forecasting challenges not experienced by regions farther east. In general, meteorological observations used to initialize the forecast models are more porous upstream from eastern Colorado. With a sometimes less-representative initial state, the weather prediction models often have difficulty with the location of cyclones developing just downstream from the mountains (i.e., low pressure development). Similarly, forecast models often have difficulty with the location of cyclones transiting the high terrain. Given the above discussion regarding the importance of pressure gradients, the placement of cyclones, and their strength and rate of intensification are all important factors in accurately forecasting the wind. Regions farther downstream tend to have better synoptic scale forecasts since the upstream representation of the atmosphere is better. Similarly, forecast models are also challenged to properly represent lee-side High Pressure systems, particularly smaller scale aspects of these systems that are directly influenced by the heterogeneity of the Colorado topography. The model uncertainly in achieving the proper location and strength of these synoptic-scale pressure systems is most pronounced in the fall, winter and spring when Colorado is closer to the jet stream position and related storm track.

Related to the prior discussion of the greater model forecast uncertainty associated with cyclones transiting the mountains, a related forecast uncertainty exists regarding the timing of the passage of fronts associated with these low pressure systems. With a less-representative initialization for the upstream conditions, the wind forecast error associated with frontal passages would be expected to be higher in eastern Colorado than regions farther east. Again, this would be much more significant factor in the fall, winter and spring seasons given the much higher frequency of frontal passages during these seasons than summer.

In addition to the north-south Rocky Mountains to the west, the eastern portion of Colorado has three topographic escarpments that run eastward from the Rocky Mountain foothills (the Raton Mesa along the southeast Colorado/northeast New

Mexico border, the Palmer Divide in central/east central Colorado, and the Cheyenne Ridge along the northeast Colorado/southeast Wyoming border). The complexities involved with terrain induced flow fields with the combination of large mountains to the west and these west-east escarpments add difficulty to forecast accuracy on the mesoscale. Historically, model resolution was a considerable constraint on the accuracy of the forecast solution when considering the flow structures associated with these smaller-width west-east ridges. This situation has improved with increasing model horizontal resolution (e.g., the North American Model (NAM) now features 12 km horizontal grid spacing) but is still a constraint with getting these mesoscale flow regimes correct in addition to the model parameterizations for getting the surface layer and boundary layer physics correct. Day-ahead forecasting accuracy implications for the three specific regions of wind production will be summarize from a mesoscale meteorological perspective are described in the following sections.

Forecasting Complexity: Southeast Colorado

In addition to the downstream uncertainty of forecasting synoptic feature placement as noted above, this region is influenced by mesoscale flow fields induced by southerly background flow interacting with the Raton Mesa. In these cases, a mesoscale gyre often sets up just downstream of the Raton Mesa axis. Since many of the installed or proposed wind farms are in the region influenced by this gyre, the accuracy of day-ahead forecasts of the presence and strength of this feature would have an influence on the expected winds at these southeast Colorado sites. Another large influence on the wind variability of wind plants in southeast Colorado involves the presence of thunderstorms and their associated outflow boundaries. Applicable to the convective season (largely spring and summer), day-ahead forecasts of convective spatial distribution and the production and distribution of thunderstorm outflow winds are often far from accurate. This is particularly applicable to this region given that the Rocky Mountains to the west and the adjacent Raton Mesa to the south are effective thunderstorm initiators. Additionally, the boundary layer convergence zones associated with the aforementioned gyre can also serve to initiate thunderstorms.

Forecasting Complexity: Central/East Central Colorado

In addition to the downstream uncertainty of forecasting synoptic feature placement as noted previously, the northern portion of this region is influenced by the mesoscale flow fields induced by southerly background flow interacting with the Palmer Divide. In this scenario, a mesoscale gyre called the "Denver Cyclone" often sets up just downstream of the Palmer Divide axis. Since some of the proposed wind farms are in the region influenced by this gyre, the accuracy of day-ahead forecasts of its presence would have an influence on the expected winds at these Colorado sites. Another large influence on the wind variability of wind plants in central/east central Colorado involves the presence of thunderstorms and their associated outflow boundaries. Applicable to the convective season (largely spring and summer), day-ahead forecasts of convective spatial distribution and the production and distribution of thunderstorm outflow winds are often far from accurate. This is particularly applicable to this region given that the Rocky Mountains just to the west and the adjacent Palmer Divide are effective thunderstorm initiators. Additionally, the boundary layer convergence zones associated with the Denver Cyclone can also serve to initiate thunderstorms. Lastly, at sites on the Palmer divide, the day-ahead forecast timing of frontal passages can be problematic given the elevation and partial barrier effects of the Palmer Divide.

Forecasting Complexity: Northeast Colorado

In addition to the downstream uncertainty of forecasting synoptic feature placement as noted previously, the southern portion of this region is influenced by the mesoscale flow fields induced by northerly background flow interacting with the Cheyenne Ridge. In this scenario, a mesoscale gyre called the "Longmont Anticyclone" sometimes sets up just downstream of the Cheyenne Ridge axis. Since some of the proposed wind farms are in the region influenced by this gyre, the accuracy of day-ahead forecasts of its presence would have an influence on the expected winds at these Colorado sites. Another large influence on the wind variability of wind plants in central/east central Colorado involves the presence of thunderstorms and their associated outflow boundaries. Applicable to the convective season (largely spring and summer), day-ahead forecasts of convective spatial distribution and the production and distribution of thunderstorm outflow winds are often far from accurate. This is particularly applicable to this region given that the Rocky Mountains just to the west and the adjacent Cheyenne Ridge are effective thunderstorm initiators. Lastly, at sites on or just downstream of the Cheyenne Ridge, the day-ahead forecast timing of frontal passages can be problematic given the elevation and partial barrier effects of the Cheyenne Ridge.

Summary

While wind generation forecasting in the eastern half of the state of Colorado would encounter some unique challenges on a regional basis, there is no evidence at this time to indicate that forecast accuracy would vary between regions in a way that would affect integration costs. There are a number of other issues related to the topic of forecasting wind generation over a large geographic area that are now receiving significant attention in formal research and development projects. As these and other future efforts come to fruition, and the science and business of wind generation forecasting matures, it is likely that the knowledge gained will counterbalance the effects of regional meteorological complexities.

Project Summary and Conclusions

The objective of the analysis in this study was to determine how the variability and uncertainty attributes of bulk-scale wind generation would affect the commitment, scheduling, and control of conventional generation sources, and what the economic consequences of those actions would be.

Summary of Results

The results of the analysis show that:

- The costs attributable to the integration of wind generation into the PSCO system range from $3.51/MWH of delivered wind energy at installed capacity level equivalent to 10% of the projected peak hourly load in 2007 up to $4.77/MWH at 15%. (Table 20).
- Uncertainty of next-day wind energy delivery has a negative impact on the nomination of natural gas deliveries for residential/industrial use and as fuel for gas-fired electric generating facilities. A methodology based on incremental storage requirements for accommodating this additional uncertainty was developed. Results show the gas system cost of integrating wind generation range from $1.26/MWH of wind generation at 10% penetration to around $1.45/MWH at the 15% level.
- The costs for additional regulation and real-time control resources are quite small at the 10 and 15% penetration levels. Costs computed from the results of statistical analysis of wind generation and system load data are less than $0.10/MWH.
- Variability of the aggregate wind generation, which is what is observed either directly or indirectly from the PSCO system control center, is strongly influenced by geographic diversity of wind project development. From the baseline wind speed and wind generation data synthesized for this project, wind generation variability does not exhibit a regional bias, i.e. variability is not influenced by a project's location within the state.
- While there are unique regional challenges for wind generation forecasting, there is no evidence at this time to conclude that day-ahead forecasting would be more difficult (and therefore contain larger errors) in any one region relative to the others.

While the methodology used to derive the quantitative results is thought to be quite sound and well founded, a number of assumptions and compromises are necessary to process the volume of data estimate annual costs. The project team believes that the net effect of these is to make the results somewhat conservative in that they would tend to overstate integration costs over what might be achieved with experienced system operators and power traders. Decisions available to the real-time "operators" conducting the analysis were purposely limited to insure some consistency and repeatability as the various cases were executed. The same can be said for day-ahead power marketing and scheduling, where purchase and sale opportunities were simplified to allow modeling in the analytical tool selected for the analysis. In reality, both groups would develop, on the basis of ever-increasing experience with wind generation, strategies that would tend to reduce the cost of managing wind generation over time.

Table 20: Phase I Integration Costs from the Hourly Analysis

Wind Penetration	Electric Production Cost Impact	Gas Supply System Impact	Total
10%	$2.25	$1.26	$3.51/MWH
15%	$3.32	$1.45	$4.77/MWH

The wind generation development scenarios constructed as the basis for this study are proving to be somewhat different than the unfolding reality in the PSCO service territory. This naturally leads to questions regarding the applicability of the results and conclusions developed here to PSCO going forward. From the results and experience gained in the project, a couple of points can be made on this topic:

- While the computed integration costs do exhibit sensitivity to input data (especially the wind generation model), the differences are certainly relatively small and in the range of variation that could be expected by altering some other study assumptions such as the assumed "rules" for real-time dispatch or the introduction of intra-day re-optimization base on short-term wind generation and load forecasts.
- The integration costs computed here are in relative agreement with those reach for similar wind generation penetration levels in other utility systems or control areas.
- Integration "costs" may be only one side of the equation for wind energy. Recent studies are showing that long-term fixed priced wind energy contracts offer the fuel cost stability normally associated with coal generation but without the potential exposure to carbon penalties[10,11]. In addition, fixed price wind contracts may be an option to hedging the natural gas used in a utilities' portfolio.

All things considered, the project team believes that the integration costs calculated here represent reasonable estimates of what would be incurred by PSCO as a result of increasing wind generation in their system.

Insights and Perspectives

As has been the case in previous analytical efforts of this type, the quantitative analysis conducted to address the objectives of the project invariably lead to a number of interested and related questions. Such questions could, of course, be explored in quantitative detail were there no limitations of project budget and schedule. Since that is obviously not practical or possible, the next best alternative is to document these issues in the hopes that future studies can build on what has been learned here to develop new knowledge and understanding.

- In comparing the two Xcel Energy wind integration studies – one for the baseload thermal system in Minnesota and this one for a system with 50% gas-fired generation – the respective makeup of the generating fleets in the respective

[10] Bolinger, M. "Hedging Future Gas Price Risk with Wind Power" presented at the Annual Meeting of the Utility Wind Integration Group, Arlington, Virginia, April 2006

[11] Clemmer, S. "Hedging Future Carbon Risk with Wind Power" presented at the Annual Meeting of the Utility wind Integration Group, Arlington, Virginia, April 2--6

operating areas were markedly different. Overall integration costs for similar relative amounts of wind generation (i.e. 15% penetration) were quite similar.

- Xcel in Minnesota has significant baseload fossil and nuclear units, and generally provides regulation capacity and load following capability with one or more of the large fossil plants. In Colorado, half of the installed generation is either simple- or combined-cycle gas-fired generation. Electric production cost impacts were greater per MWH of wind energy for the Minnesota system, but when the gas supply impacts on the Colorado operating area are included, the costs were nearly equivalent ($4.60/MWH vs. $4.77/MWH)
- Access to additional flexible and modestly-priced resources can reduce the integration cost for wind generation. In the Xcel-PSCO study, the Cabin Creek pumped storage facility is an excellent example of this type of resource. Wind generation in the system also had the effect of unloading flexible simple-cycle gas-fired generation, which could then be used in turn to provide ramping, regulation, and reserve capability for managing wind energy delivery.
- A market with a competitive real-time or balancing market is another way additional controllable supply resources for managing generation can be made available, as was illustrated in the previous study for Xcel-NSP. Short of an actual market, the consolidation of control areas to reduce the overall regulation and balancing requirements would have similar impacts on wind integration cost.
- New generation technologies are now entering the marketplace that could reduce the costs for integrating wind energy. Newer simple-cycle gas turbines based on aircraft engine technology, for example, have attributes that appear to complement wind generation quite well. These units are highly maneuverable and incur no maintenance penalties for frequent stops and starts. They are also relatively efficient at maximum loading down to less than half of nameplate rating. With this apparent match to wind generation, how such technologies might be used to optimize the entire portfolio of resources will become an increasing interesting topic.
- Day-ahead wind generation forecasts are an important input to the methodology used in this and other studies. Sensitivity of integration costs to the accuracy of these day-ahead forecasts is a topic for which there exist only a small number of actual data points. Better knowledge here could help to guide the evolution of wind generation forecasting technology and methods, and could also contribute to the development of improved strategies for resource scheduling or market bidding.
- The costs of the incremental regulation for wind generation were computed using a marginal capacity value. With the methodology used in this study, there are additional costs incurred at the hourly level since the incremental capacity is reserved and not used to serve load. The amount of these costs accrued at the hourly level could be determined by running cases with and without this incremental capacity reserved by the optimization and dispatch tool. The difference between the two cases would consist of the opportunity cost for units assigned to regulating duty by system operators.

Wind Integration Study Report
Of Existing and Potential
2003 Least Cost Resource Plan Wind Generation

Xcel Energy Transmission Planning

April 2006

I. Summary

This Interconnection System Impact Study Report summarizes the analyses of current and potential future wind generation in the Public Service Company (PSCo) of Colorado electrical system. Presently, PSCo has about 280 MW of wind resources connected to its transmission system in Colorado. Those resources consist of four projects: The 30 MW Ponnequin Facility; the 30 MW Ridge Crest (Peetz) facility; the 160 MW Colorado Green Wind Farm; and most recently, as a result of the 2003 Least Cost Resource Plan Renewable Energy Request for Proposals, the 60 MW Spring Canyon project. Based on the current All-Source Solicitation, it appears likely that an additional 775 MW of wind generating capacity may be added to the system in the next two years. Therefore, the total potential wind generating capacity on the PSCo system will be about 1,057 MW by 2008. Table 1 lists the existing and potential wind projects and Figure 1 provides a visual representation of where they are located.

Table 1 Existing and Potential Wind Projects for PSCo

Facility	Interconnection	Capacity (MW)	Existing /New	In Service Date
Ponnequin	Ponnequin ties into the Cheyenne – Ault 115kV line.	30	Existing	Jan 1999
Ridge Crest	Peetz, (on the Sidney – Sterling 115kV line), via a 2-mile 115kV line.	30	Existing	Sep 2001
Colorado Green	Lamar, via a 44-mile 230kV line.	162	Existing	Dec 2003
Spring Canyon	Spring Canyon ties into the Sidney – N.Yuma 115kV line	60	Existing	Jan 2006
Logan	Pawnee, via a 70-mile 230kV line.	400	New	Jul 2007
CO Green Expansion	Lamar, (connects to the existing Co. Green facility)	75	New	Oct 2007
Cedar Creek	Ties into the RMEC-Green Valley 230kV lines, via a 50-mile 230kV line.	300	New	Dec 2007

Conclusions & Recommendations

1. The PSCo transmission system is able to accommodate the full complement of existing and potential wind generation. Note that during peak load periods, gas-powered generation may be reduced to accommodate the wind resources, if necessary.

2. Powerflow (steady state) analysis indicates that the wind projects can be integrated into the PSCo system with no adverse affects. Studies of both system intact and single contingency scenarios did not reveal any overloaded facilities or voltage violations caused by the wind facilities.

3. The studied wind facilities do not put the PSCo transmission system at risk of any transient or voltage instability[1]. Studies show that the electric system can withstand the complete loss of any of the projects.

[1] Operating procedures are utilized for disturbances in the Lamar area.

4. Studies showed that the low voltage ride-through (LVRT) capabilities of the wind generation were effective on all but the existing Ridge Crest project. Although the older machines in use at Ridge Crest don't have the controls or capabilities of the newer machines, there is no impact to the reliability of the regional system operation.

II. Background

This Study Report was prepared in partial response to Item No. 3 of the August 6, 2004 Stipulation between the Staff of the Colorado Public Utilities Commission and Public Service Company of Colorado (PSCo) with respect to wind studies. Item No. 3 stated the following:

"The Company shall perform powerflow and stability analyses, using 2007 power flow cases, of the portfolio of resources selected by the Company in response to the Renewable Energy RFP approved by the Commission in Docket 04A-325E. Public Service will use its reasonable best efforts to employ the latest commercially available models to assess the wind generation's impact on the stability of the Public Service system. To the extent such analyses identify problems with system stability, the Company will recommend appropriate solutions to address these problems. Public Service will also evaluate the reliability impacts of potential wind generation in its long-term planning studies."

Subsequent to the issuance of the Renewable Energy RFP, an All Source RFP was issued in which both wind generation proposals as well as thermal generation proposals were submitted. Therefore, although the Stipulation recommended using 2007 study models, this study focuses on the issues of system performance as expected in the year 2008 to illustrate the analyses for not only the resources selected from the Renewable Energy RFP, but also include renewable energy projects that have been indicated by Xcel Energy Markets (XEM) as potential candidates in the All-Source RFP. Additional studies are being performed to fully evaluate the impacts of the entire All-Source collection of resources.

This study also models potential thermal resources that could be in service in 2008. Those resources are discussed in more detail in the following Methodology section.

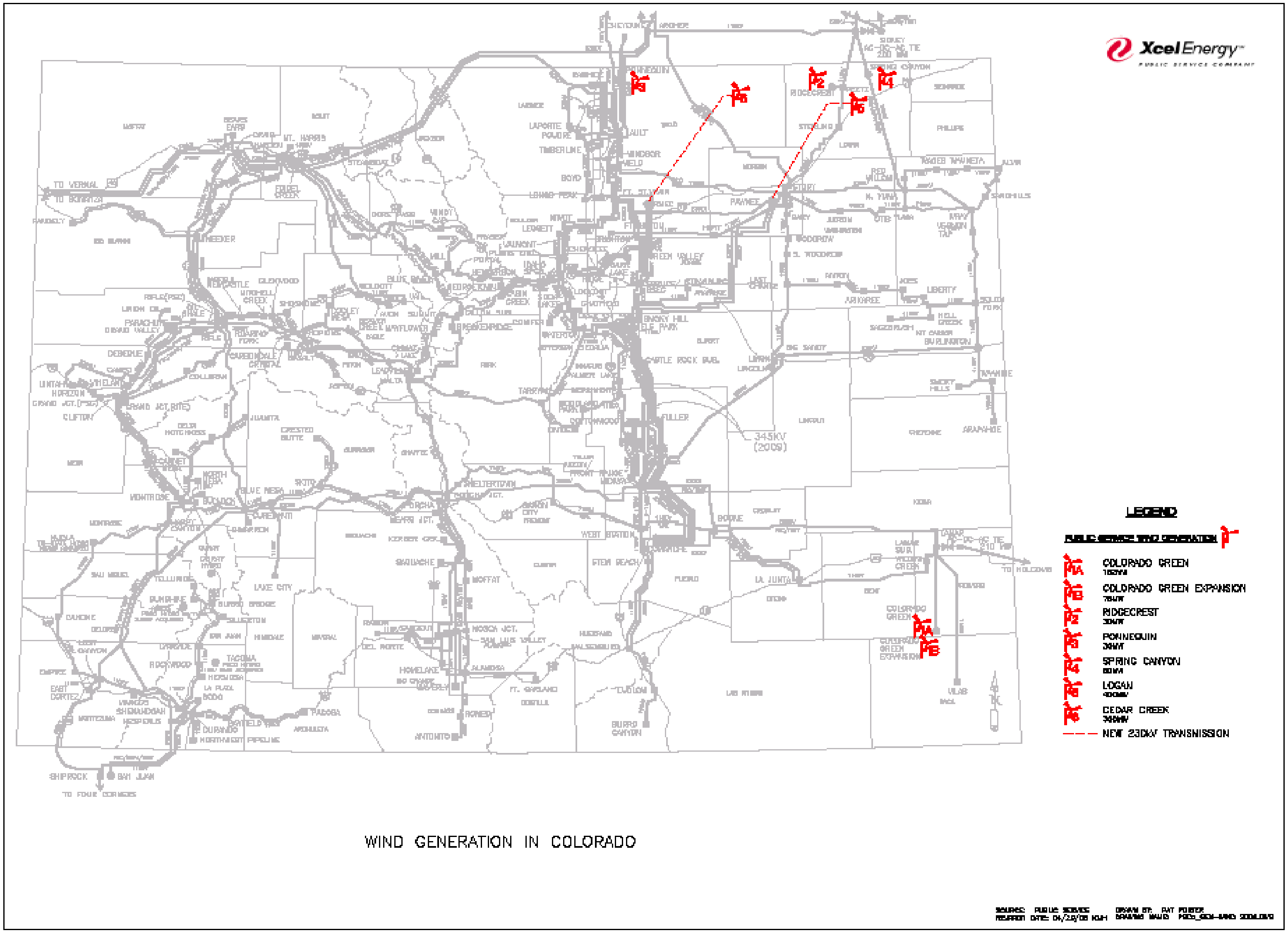


Figure 1 General Locations of Wind Projects in PSC

III. Methodology

A. System Models

Studies were conducted using 2008 system models and used two load levels. A peak load case was created by modeling maximum expected summer loads. In addition, a minimum load case was created to model a spring season scenario. Since experience shows that wind generation is highest during light load periods, the minimum load case provides a good model to test the ability of the system to accommodate maximum levels of wind power penetration. The study area was essentially the state of Colorado, which in the system models includes the powerflow areas of PSCo and Western Area Power Administration's Rocky Mountain Region (Western RM). For all cases, the PSCo control area slack bus was the Cherokee No. 3 generator, and the Western RM control area slack bus was at Yellowtail. The system models were prepared using existing Western Electricity Coordination Council (WECC) models. The WECC cases represent the entire Western Interconnection in full detail at the planning level. Dynamics (transient stability) system models were set up for both load scenarios. The models were tested under non-disturbance conditions to verify that the system is in balance before any disturbance testing was conducted.

1. Peak Load

The summer peak case was built from the 2007 HS2A WECC-approved base case. The PSCo powerflow area load was derived from the 2008 summer peak forecast provided by PSCo's Regulated Risk Service & Generation Modeling Group on April 26, 2005. The Western RM control area demand for the 2008 heavy summer case was obtained by averaging the control area demand in the 2007 HS2A WECC-approved case and the control area demand in the 2009 HS1A WECC-approved case. For the peak load models, the PSCo powerflow area load was about 7550 MW, and the Western RM load was about 4500 MW.

Generation in the Western-RMR control area was adjusted to account for the increase in demand from the 2007 heavy summer case. A representative generation dispatch was used to serve the load change in the PSCo control area. The wind generation dispatch is discussed under Section B, Wind Representation. In order to evaluate the capabilities of the system for firm transfer levels, the case was modified to simulate high TOT 3 and north to south system flows. Modifications resulted in increasing Tot 3 flows from 1,185 MW north-to-south to 1,445 MW north-to-south and increased the TOT7 flow from 565 MW north-to-south to 763 MW north-to-south.

2. Minimum Load

The 2008 Spring Minimum Load case was based on a WECC-approved 2006 Light Spring Load Case (2006LSP2-SA). The refinements applied to complete the case for the PSCo system that were used in this wind integration study included a further load reduction by approximately 25% from the original 2008 light load case. This was done after reviewing the information on the actual load levels on an hourly basis for the entire year of 2005. This information indicated that the original WECC case had a "low" load but not a minimum load condition. The PSCo loads in the 2008 Spring power flow case were then scaled to match the minimum load experience in 2005 adjusted for load growth. The entire remainder of WECC load was left unchanged in order to leave the load/generation balance undisturbed in that part of the system. For the minimum load models, the PSCo powerflow area load was about 2900 MW, and the Western RM load was about 2800 MW.

The generation dispatch was significantly different for the minimum load case than for the peak case. The generating schedule applied was such that all gas-fired generation except the generators at the Rocky Mountain Energy Center (RMEC) were modeled off-line, the wind generation was assumed to be at maximum output (1057 MW), and the remaining PSCo generation in the case is coal-fired. Details of the minimum dispatch are shown in Appendix A.

3. Transmission

The expected transmission system configuration for the 2008 heavy summer season was modeled for all cases. Significant planned PSCo transmission projects represented in the case included the following:

- Denver Terminal – Dakota – Arapahoe 230-kV line
- Chambers 230/115-kV Transmission Intertie Project
- Capitol Hill – North 115-kV underground line upgrade
- Conoco – Sandown 115-kV line project
- Second Sulphur 230/115-kV autotransformer
- Sulphur-Parker 115 kV #2
- Walsenburg – Gladstone 230-kV line (Tri-State G&T project)

B. Wind Representation

1. Generation Modeling

As previously discussed, there are four existing wind projects interconnected to the PSCo system, which have a total nameplate capacity of 282 MW. Based on information at the time of this report, there is the potential for an additional 775 MW of wind capacity that could be added by 2008. Table 2 presents a tabulation of the machine manufacturer and type, as well as the number of such machines at each site, for both existing projects and the potential wind farms based on information from bidders. This information was used to create the wind models for system studies.

Table 2 Wind Generation Locations and Machine Types

Wind Project	Manufacturer	Number of Machines	Type	Machine Size (MW)	Total (Apx MW)
Existing:					
Ponnequin	Vestas	15	47A	0.66	10
Ponnequin	NEG Micon	29	NM 48	0.70	20
Ridge Crest	NEG Micon	33	NM900/52	0.90	30
Spring Canyon	GE	40	1.5 sle	1.50	60
Colorado Green	GE	108	1.5 sle	1.50	162
New:					
Logan	GE	266	1.5 sle	1.50	400
Cedar Creek	GE	200	1.5 sle	1.50	300
Co. Green Expansion	GE	50	1.5 sle	1.50	75

Each of the existing and potential wind farms are comprised of a number of wind turbines, each with their own step-up transformers, with the high-side typically 34.5 kV. The 34.5-kV collector system will deliver the power generated by these individual turbines to the transmission system with one or more 34.5/230- or 34.5/115-kV transformers. For this study, all of the wind turbines connected to the major step-up transformers were aggregated to an equivalent single generator with generator step up transformer that was connected to the bulk transformer. Figure 2 shows how the wind generation was typically modeled, using the Colorado Green as the example. Each of the two generators in Figure 2 is the electrical equivalent of 54 individual 1.5 MW turbines, with the 0.575/34.5 kV transformer the equivalent of the 54 individual units.

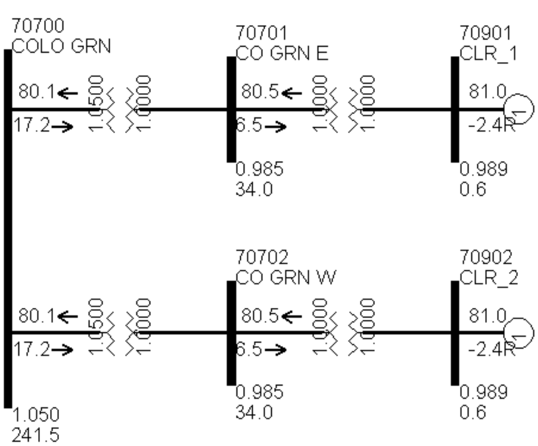


Figure 2 Typical Wind Farm Representation

The power flow cases were modified to represent the existing and potential wind farms in this manner, to enable both steady state and stability analyses to be readily performed.

Most of the wind turbine capacity (close to 1000 MW) that will be on the PSCo system in 2008 is currently expected to be GE 1.5 MW wind turbines. In addition, there are a number of Vestas units at Ponnequin. With the cooperation of their manufacturers, detailed modeling of both of these types of wind turbines have been developed for PSS/E that will predict their response in both steady state and system disturbance conditions. At the present time, there are no dynamic models of the NEG Micon NM48 wind turbines like those at Ponnequin available for use with PSS/E. Since they were installed at the same time as the Vestas units and the Ponnequin site can only provide 30 MW, that capacity has been modeled using the Vestas models; this is consistent with the approach that has been used in other stability studies for generation in this area. The NEG Micon NM900/52 wind turbines at Ridge Crest are older induction generators that do not have the power electronics like the newer GE turbines to help provide reactive power support. The Ridge Crest turbines have been modeled as an aggregated 30 MW induction generator.

2. Interconnections

The Cedar Creek generation was modeled as being interconnected to both 230-kV circuits between RMEC and Green Valley through a 50-mile 230-kV line from the project.

The Logan generation was modeled as being interconnected to the Pawnee bus through a 70-mile 230-kV line from the project.

The Colorado Green Expansion was modeled at the Colorado Green 230kV bus, which is where the existing Colorado Green generation is connected.

3. Dispatch

The peak load models reflect the generation pattern that may be expected for the summer peak. The Colorado Green generation was fixed at 60 MW, which is a good historical level of generation during peak load periods. Ponnequin, Spring Canyon, and Ridge Crest generation were modeled off line, since their typical output is zero or very low during the summer peak periods. Figure 3 shows the wind generation level for July 17, 2005, which was the peak load day for that year. In the peak models, gas-fired generation in the vicinity of the Cedar Creek and Logan wind projects was reduced to accommodate the wind generation. If necessary, this will be the expected operation of those facilities. After allowing for line losses of about 8.5 MW on the radial line from Cedar Creek, generation at RMEC was reduced by 291.5 MW to accommodate the net power delivered to the PSCo system from Cedar Creek. Generation at the two combustion turbines at Manchief and other gas-fired generation at Brush, were reduced by 378 MW to accept the wind output delivered from the Logan project.

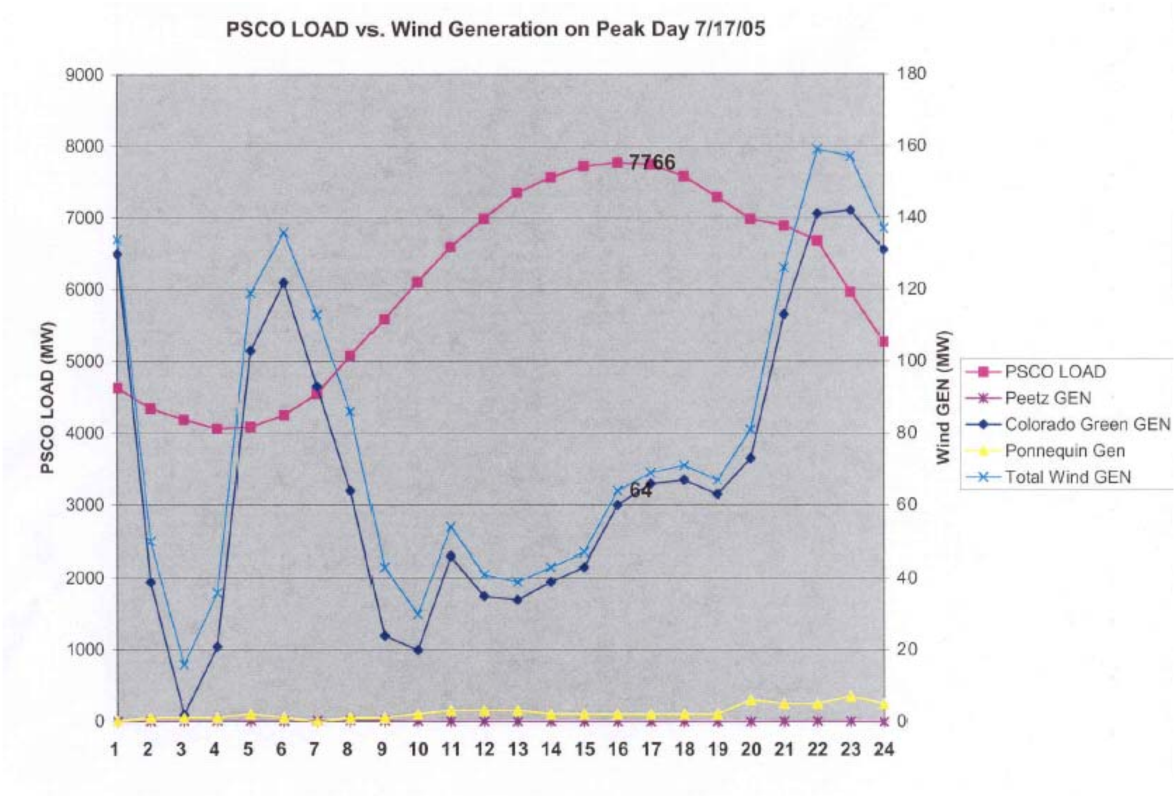


Figure 3 Typical Wind Generation for a Peak Day

In the minimum load cases, the wind projects were modeled at full name plate capacity.

C. Additional Resources

During the course of the All-Source Solicitation, Transmission Plannning has evaluated several "portfolios" of generation resources, including not only wind, but also several thermal projects. These studies included some potential thermal generation being considered in the All-Source evaluation. These projects were also discussed in the All-Source RFP Bid Evaluation Report, dated December 2005. The thermal resources modeled in these studies are shown in Table 3.

Table 3 Potential 2008 Resources from All-Source Solicitation

Bid	Capacity - MW	Type of Resource	In Service Date
G025	260	Gas-fired CTs	6/1/07
G029	270	Gas-fired CTs	5/1/07

The resources listed in Table 3 were added to both the peak and the minimum load models.

D. Software

The development of power flow cases and the stability analyses for this study used Siemens PTI's PSS/E version 29.4 software. Steady state contingency analysis used MUST version 7.0 to identify lines or transformers that would be overloaded under base case or single contingency conditions. The V-Q analysis to evaluate voltage stability by evaluating reactive reserve margins used the latest release of PSS/E, version 30.1.

IV. Planning Criteria

The Study evaluated the transmission requirements associated with the interconnection of the potential resources to the PSCo Transmission System. The Study consisted of steady state power flow analysis and dynamic stability analyses. The power flow analysis identified thermal or voltage limit violations. PSCo adheres to NERC/WECC Reliability Criteria, as well as internal Company criteria for planning studies. During system intact conditions, criteria are to maintain transmission system bus voltages between 0.95 and 1.05 per-unit of system normal conditions, and steady state power flows within 1.0 per-unit of all elements thermal (continuous current or MVA) ratings. Operationally, PSCo tries to maintain a transmission system voltage profile ranging from 1.02 per-unit or higher at generation buses, to 1.0 per-unit or higher at transmission load buses. Following a single contingency element outage, transmission system steady state bus voltages must remain within 0.90 per-unit and 1.10 per-unit, and power flows within 1.0 per-unit of the element's continuous thermal ratings. Impacts on the neighboring utilities were monitored, and were addressed in the scope of this study as appropriate.

The NERC/WECC Planning Standards for System Performance was followed for the stability analysis. In the WECC Disturbance-Performance criteria, for the loss of a single element (line or transformer), the maximum allowed voltage dip after fault clearing is 25% for load buses. This dip cannot exceed 20% for more than 20 cycles. The allowed post-transient voltage deviation, 1 to 3 minutes after the fault, is 5% for all buses. In addition, the frequency at any bus cannot be below 59.6 Hz for 6 cycles or more at any load bus.

V. Steady-State Analysis

A. Peak Load

The studies were benchmarked by running contingency analysis on the peak case without the additional wind generation. All buses, lines and transformers of 69 kV and above in the PSCo and Western RM study areas were monitored. Single contingency analysis was performed for all lines and transformers within the same area. Outages of single generating units were also studied. The results were reviewed for violations in the areas around the interconnection points.

Next, contingency analysis was conducted on models that included the additional wind generation to determine the electric system's capability to carry the additional generation from new facilities. The results were compared to the benchmark analysis that did not contain the new generation. Lines and transformers that exhibited higher loadings with the additional generation than in the benchmark cases were identified, as well as any significant voltage deviations.

Results

- Since the new wind generation associated with Logan, Cedar Creek, and Colorado Green Expansion were offset by nearby gas generation and the Lamar DC Tie, no element loadings or voltage deviations due to the additional wind projects were identified.
- For the loss of the full 400 MW of wind generation at Logan, studies showed that the thermal generation around Pawnee would be able to maintain voltage at the Pawnee 230-kV bus at 1.03 pu and the voltage at the Logan 230 kV bus would be relatively unchanged at 1.041 pu.
- For the loss of the full 300 MW of wind generation at Cedar Creek, and without the loss of the radial line, voltage at the Cedar Creek 230-kV bus remained near 1.035 pu, and the units at RMEC maintained voltage on that 230-kV bus at 1.03 pu.

B. Minimum Load

Benchmark and contingency analyses were performed as with the peak load models. In addition, some studies were performed to test the ability to control system voltages to within the allowable range under WECC pre-contingency criteria. This involved removing all the wind generation and replacing it by already operating coal-fired steam units at Pawnee, Comanche, and Cherokee. Voltages at the radial ends of the wind project interconnection lines and the collector systems were checked to verify that they did not exceed 105% of nominal voltage. Both Logan and Cedar Creek projects had slightly high voltage before any changes were made in coal unit generator voltages, but minor changes in the voltage set points, on the order of 1%, were adequate to reduce reactive flows by about 10 MVAR in the areas of the projects. This was enough to bring them into compliance, and still leave 30-40% of the reactive power capability of the steam units available for other possible voltage control needs.

Results:

- Contingency analysis did not reveal any issues, as would be expected at this low a system loading.
- The voltage profile was also found to be quite good with minimal shifts in reactive generation to maintain a smooth voltage profile across the system. In general, the system voltages were close to 100% of nominal value.
- There were no significant voltage deviations when compared to the benchmark results.
- For the prospective loss of the full 400 MW of generation at Logan, studies showed that there is more than adequate capability to manage the swing on internal generation as well as lightly loaded tie lines.

VI. Dynamics Analysis

The objective of this assessment was to review system performance with the addition of the new resources and, if necessary, identify options that could improve system stability during periods of system stress.

The dynamics case setup for this analysis used the WECC model database for dynamics data. All wind machines were represented by the most recently developed PTI wind generator dynamic models available for the machines. All but the NEG Micon machines have sophisticated blade pitch control, VAR control and low-voltage ride-through capability, as well as relaying to remove them from service where the voltage and wind conditions are possibly damaging to either the system or the machines. A non-disturbance case was modeled to verify that dynamics modeling would initiate properly and to establish a good benchmark for performance.

A. Peak Load

The system intact stability analysis was performed to determine the effects that adding the three wind farms and two potential combustion turbine facilities as part of the All-Source Solicitation would have on the transient stability of the system by comparing the responses both with and without the additional resources. A number of disturbances were modeled and are included in Appendix B, Table B-1. The disturbances focused on the regions near the points of interconnection for the added resources, but several general system disturbances were also modeled. All of the studied faults were three-phase faults, with most on the 230-kV system, with faults cleared in 4 cycles. All disturbance cases initiated the fault at 0.2 seconds and were run for 10 seconds. For the PSCo existing generating resources, generator buses were monitored for rotor angles, electric power, terminal voltage, mechanical power, speed and frequency. Additionally, voltages on all buses operating at 230-kV and above were monitored.

Results

All disturbances except for one were found to be stable and well damped. The exception was for a fault at Boone, and subsequent tripping of the Boone – Lamar 230-kV circuit. However, this is an existing condition, and operating procedures are in place to trip the Lamar DC Tie and the existing wind generation as needed. Appendix C lists the disturbances and shows that there are no violations of the maximum transient voltage deviation criteria. Reviewing the results of this analysis, the system response is well damped.

At the end of the 10-second analysis, the transient voltage deviations for two were slightly above 5%:

- For a disturbance that modeled a fault at Laramie River Station (LRS) and the subsequent clearing of the fault by opening the LRS – Ault 345-kV circuit, the voltage at Ponnequin was about 6% below the pre-fault level. However, as the powerflow studies showed, once tap-changing transformers and switched

capacitors have the chance to operate, the voltage at Ponnequin will increase to acceptable pre-fault levels.
- For a disturbance that modeled a fault on the St. Vrain – Isabelle 230-kV circuit, the voltage at the Isabelle 230-kV bus was about 5.5% below the pre-fault level. However, it was determined that these results are due to the potential thermal project in the region, and not associated with any of the wind projects.

With a fault at Pawnee that is cleared in 4 cycles, the voltage at the Logan wind farm was above 0.60 pu. Similar results were seen at the Cedar Creek wind farm for a fault at the interconnection point for Cedar Creek near RMEC. Since these two wind farms will have low voltage ride through capability and are interconnected through a long transmission line, system disturbances that are not on the radial line to the wind farms should not impact their operation and would allow them to remain online during peak load periods.

A fault and subsequent loss of the Logan facility and radial transmission line does not have any impact on the stability of the system other than the loss of generation and the resultant change in machine angles. There does not appear to be any issues with voltages at the potential wind farms based on the use of GE turbines as proposed and the long transmission lines.

B. <u>Minimum load</u>

A total of 49 disturbances were modeled for the minimum load conditions and are listed in Appendix B, Table B-2. Of these, 48 were three phase faults followed by a line or transformer trip. The only non-fault test was for the sudden loss of generation at Pawnee. In some of the contingencies, the loss of a single line also caused loss of generation as well. This is true for the radial 230 kV lines that interconnect the Logan, Cedar Creek, and Colorado Green projects.

All cases tested except the two for the Ridge Crest site and the loss of Boone – Lamar 230 kV line were found to be stable, and low voltage ride-through constraints met. It should be noted that in some cases the low voltage constraint conditions are such that the wind machines should shut down, and they did. This was found to be true for the Spring Canyon and Ponnequin cases where the fault applied was at the project's interconnection bus. Testing of the ability to "ride through" fault conditions at more remote buses were found to be successful in all cases, including for the interconnection points for the Logan and Cedar Creek projects.

The instability of the Ridge Crest Project is tied to the vintage of the NEG Micon 900/52 wind machines. These machines have very limited ability to respond to system conditions, since they have no internal reactive power control or production capability, have fixed blade position and none of the relaying to facilitate otherwise low voltage ride-through. However, due to the breaker configuration on the Sidney – Sterling 115kV line, in actual practice, a fault on that line would result in the entire line and the wind farm being taken out of service. Therefore there would be no impact to the surrounding transmission system.

VII. Reactive Reserve Analysis

Recently the major problem occurring with US electric systems is voltage collapse. The Canadian-Northeast blackout is an example of the high cost of a system voltage collapse. It requires considerable effort to study and identify if a system is susceptible to such an event. Voltage collapse is mitigated by the addition of new generating units with the capability producing reactive power. Generator ratings of 0.85 power factor output provide the most mitigation. The addition of high voltage transmission lines lowers the I^2X_L or MVAR requirement and produces reactive power as a function of line charging. Both the addition of generation and transmission lines directly or indirectly are a part of the generation bids, so the system in the short term should be less likely to enter into voltage collapse.

Based on the results of the transient stability analyses that indicated a well-damped system where voltages returned to prefault levels, the stability performance of the PSCo system appears to be robust around the major load center, the Denver metropolitan area. The two significant wind farms included in this study (Logan and Cedar Creek) are expected to be connected to the PSCo system near other generation that will generally be running during peak periods. Thus to evaluate the reactive reserve impact of adding new wind generation, the long radial lines to the PSCo system from the wind farms and the other potential All-Source generation, the reactive reserve analysis needed to be focused on some other location in the transmission system, somewhat removed from generation but still in the study region. The Daniels Park 230-kV bus was selected as the bus to use for this analysis.

To test the premise that the new generation including wind farms coupled with the transmission system additions should reduce the likelihood of voltage collapse, a QV analysis was conducted at the Daniels Park 230 kV Substation. Two cases were selected for analysis. The first case benchmarked the performance before any new generation is added. The second case included the potential All-Source generation for 2008. The worst single contingency outage appeared to be the loss of the Pawnee to Daniels Park 230 kV line. The case with added generation has substantially more reactive power available than the benchmark case.

For the benchmark case, the loss of the Pawnee – Daniels Park 230-kV circuit, the reactive reserve margin was found to be about 400 MVAR. For the case with the added generation, the reactive reserve margin was found to be about 580 MVAR. Plots of the QV analysis are shown in Appendix D. The difference between the minimum and the zero MVAR axes is the MVAR margin. The lower the minimum point the more margin, and the better the system is able withstand voltage collapse.

Therefore, the generation additions provide more reactive margin and the PSCo system will be even stronger in terms of it ability to withstand a voltage collapse situation.

Appendix A

Table A- 1 Generation Summary for 2008 Minimum Load Conditions

BUS#	NAME BSKV	ID	Machine Status	PGEN	QGEN	PMAX	PMIN	Power Swing Capability Up	Power Swing Capability Down
Fossil Fueled Generators									
70103	CHEROK1 15.5	1	On	60.0	-9.7	117.0	50.0	57.0	-10.0
70104	CHEROK2 15.5	1	On	60.0	-9.9	114.0	50.0	54.0	-10.0
70105	CHEROK3 20.0	1	On	67.5	-15.1	165.0	50.0	97.5	-17.5
70106	CHEROK4 22.0	1	On	200.0	-16.0	383.0	150.0	183.0	-50.0
70119	COMAN 1 24.0	1	On	230.0	40.7	360.0	200.0	130.0	-30.0
70120	COMAN 2 24.0	1	On	230.0	40.2	365.0	200.0	135.0	-30.0
70310	PAWNEE 22.0	1	On	340.0	100.5	530.0	300.0	190.0	-40.0
70350	RAWHIDE 24.0	1	On	100.0	40.5	290.0	45.0	190.0	-55.0
70446	VALMONT 20.0	1	On	113.0	45.3	188.0	100.0	75.0	-13.0
70588	RMEC1 18.0	1	On	112.0	12.3	192.0	67.0	80.0	-45.0
70589	RMEC2 18.0	1	On	112.0	12.3	192.0	67.0	80.0	-45.0
70591	RMEC3 18.0	1	On	106.0	17.8	201.0	25.0	95.0	-81.0
				1,730.5				1,366.5	-426.5
Pumped Storage Hydro									
70069	CABCRKA 13.8	1	On	-115.0	-20.9	162.0	-120.0	277.0	-5.0
70070	CABCRKB 13.8	1	On	-115.0	18.8	162.0	-120.0	277.0	-5.0
				-230.0				554.0	-10.0
Lamar DC Tie		1	On	-50.0	-34.2	210.0	-210.0	260.0	-160.0
Wind Generators									
70723	RDGCREST34.5	1	On	29.7	-3.2	29.7	0.0	0.0	-29.7
70901	CLR_1 .575 (Co Green)	1	On	81.0	10.3	81.0	0.0	0.0	-81.0
70902	CLR_2 .575 (Co Green)	1	On	81.0	10.3	81.0	0.0	0.0	-81.0
70903	CLR_3 .575 (W014A)	1	On	75.0	26.0	81.0	0.0	6.0	-75.0
70915	CLR_1 .575 (Logan)	1	On	166.3	31.4	166.5	0.0	0.2	-166.3
70916	CLR_2 .575 (Logan)	1	On	166.3	31.4	166.5	0.0	0.2	-166.3
70917	CLR_3 .575 (Logan)	1	On	65.9	6.1	66.0	0.0	0.1	-65.9
70921	CLR_1 .575 (Spring C)	1	On	60.0	6.4	60.0	0.0	0.0	-60.0
70922	Cedar Creek_1	1	On	150.0	18.7	150.0	0.0	0.0	-150.0
70923	Cedar Creek_2	1	On	150.0	18.7	150.0	0.0	0.0	-150.0
70931	CLR_1 .690 (Ponnequin)	1	On	5.3	-2.6	5.3	0.0	0.0	-5.3
70932	CLR_2 .690 (Ponnequin)	1	On	5.3	-2.6	5.3	0.0	0.0	-5.3
70933	CLR_3 .690 (Ponnequin)	1	On	5.3	-2.6	5.3	0.0	0.0	-5.3
70934	CLR_4 .690 (Ponnequin)	1	On	5.3	-2.6	5.3	0.0	0.0	-5.3
70935	CLR_5 .690 (Ponnequin)	1	On	4.6	-2.3	4.6	0.0	0.0	-4.6
70936	CLR_6 .690 (Ponnequin)	1	On	4.6	-2.3	4.6	0.0	0.0	-4.6
				1,055.6				6.5	-1,055.6

The dispatch process will be significantly different for the spring minimum load case. As one might expect in looking at minimum load conditions, the transmission system was lightly loaded. The generating schedule applied was such that all gas-fired generation except the generators at the Rocky Mountain Energy Center (RMEC) were out of service, the wind generation was assumed to be at maximum output, and the remaining PSCo generation in the case is coal-fired. Also, the Cabin Creek Pumped Storage Project was assumed to be pumping at nearly full capability. The system load plus Cabin Creek plus losses was approximately 3,278 MW. As can be seen in Table 5, the coal-fired units are operating above their minimum allowable operating points. With the RMEC units operating, the ability to load-follow is adequate. If there were a sudden increase in load, the Cabin Creek pumping operations could be curtailed, or even put into generating mode. Further, in the unlikely event that there were a sudden drop in the level of wind across the entire eastern part of Colorado, there is more than adequate capability to increase generation on already-operating units, as noted in Table 5 under the "Up" Power Swing Capability heading. There is even some further room for lower load with this schedule, as seen in the "Down" column. With the ability to use RMEC and Cabin Creek to manage load swings of approximately 500 MW or more, there is little likelihood of having to manage coal unit pulverizer cycling in a disadvantageous way, or for there to be concern of putting coal units into boiler flame stability danger. Further, there is high likelihood that one or more of the large coal units will be out of service for maintenance, a typical use of this time period's low demand.

Appendix B

Table B- 1 Peak Load Stability Disturbance List

		Faulted End	Circuit Faulted	From Bus No	To Bus No
General Contingencies					
	GCON1	Comanche	Comanche - Midway 230 kV	70122	70286
	GCON2	Comanche	Comanche - Fuller 230 kV	70122	73477
	GCON3	Daniels Park	Daniels Park - Midway PS 230 kV	70139	70286
	GCON4	Midway PS	Midway PS - Daniels Park 230 kV	70286	70139
	GCON5	Lookout	Lookout - Cabin Creek 230 kV	70266	70072
	GCON6	Lookout	Lookout - West PS 230 kV	70266	70480
	GCON7	Cherokee	Cherokee - Lacombe 230 kV	70107	70324
	GCON8	Boone	Boone - Midway PS 230 kV	70061	70286
	GCON9	Boone	Boone - Lamar 230 kV	70061	70254
	GCON10	Boone	Boone - Comanche 230 kV	70061	70122
	GCON11	Lamar	Lamar - Colorado Green 230 kV	70254	70700
	GCON12	Lamar	Lamar - Lamar DC	70254	70801
	GCON13	Story	Story - LRS 345 kV	73193	73108
	GCON14	LRS 345 kV	LRS 345/230 kV Transformer	73108	73107
	GCON15	LRS	LRS - Ault 345 kV	73108	73012
	GCON16	Ault	Ault - Craig 345 kV	73012	79014
	GCON17	Ault	Ault - Windsor 230 kV	73011	70474
	GCON18	Ault	Ault - Weld 230 kV	73011	73212
W009 Contingencies					
	PCON1	Pawnee	Pawnee - Ft. Lupton 230 kV	70311	70192
	PCON2	Pawnee	Pawnee - Quincy 230 kV	70311	70343
	PCON3	Pawnee	Pawnee - Story 230 kV	70311	73192
*	PCON4	Pawnee	Pawnee - W009 230 kV	70311	70902
	PCON5	Pawnee 230 kV	Pawnee 230/22.1 kV Transformer	70311	70310
	PCON6	Pawnee	Pawnee - Daniels Park 230 kV	70311	70139
*	PCON7	W009 230 kV	W009 230/34.5 kV transformer	70542	70815
W022 Contingencies					
*	RCON1	W022 Tap	W022 Tap - W022 230 kV	70545	70546
*	RCON2	W022 Tap	W022 Tap - Green Valley 230 kV	70545	70048
*	RCON3	W022 Tap	W022 Tap - RMEC 230 kV	70545	70590
*	RCON4	W022 230 kV	W022 230/34.5 kV transformer	70546	70823
*	RCON5	RMEC	RMEC - W022 Tap 230 kV	70590	70545
	RCON6	RMEC	RMEC - Green Valley 230kV	70590	70048
G025 Contingencies					
	SCON1	Spruce	Spruce - Picadilly 230 kV	70528	70530
	SCON2	Spruce	Spruce - Chambers 230 kV	70528	70539
	SCON3	Spruce	Spruce - Smoky Hill 230 kV	70528	70396
	SCON4	Spruce	Spruce - Sky Ranch 230 kV	70528	70392
	SCON5	Spruce	Spruce - Green Valley 230 kV	70528	70048
	SCON6	Spruce 230 kV	Spruce 230/18 kV Transformer	70528	70562
*	SCON7	Spruce 230 kV	Spruce/G025 230/18 kV Transformer	70528	70571
G029 Contingencies					
*	FSVCON1	G029	G029 - Ft. St. Vrain 230 kV	70592	70410
*	FSVCON2	G029	G029 - Isabelle 230 kV	70592	70544
*	FSVCON3	G029 230 kV	G029 230/18 kV transformer	70592	70593
	FSVCON4	Ft. St. Vrain	Ft. St. Vrain - Ft. Lupton 230 kV	70410	70192
*	FSVCON5	Ft. St. Vrain	Ft. St. Vrain - G029 230 kV	70410	70592
	FSVCON6	Ft. St. Vrain	Ft. St. Vrain - Isabelle 230 kV	70410	70544
	FSVCON7	Ft. St. Vrain	Ft. St. Vrain - Longs Peak 230 kV	70410	73116
	FSVCON8	Ft. St. Vrain	Ft. St. Vrain - Fordham 230 kV	70410	73562
	FSVCON9	Ft. St. Vrain	Ft. St. Vrain - Windsor 230 kV	70410	70474
	FSVCON10	Ft. St. Vrain	Ft. St. Vrain - Weld PS 230 kV	70410	70471
	FSVCON11	Ft. St. Vrain	Ft. St. Vrain - Valmont 230 kV	70410	70447
	FSVCON12	Ft. St. Vrain	Ft. St. Vrain - Green Valley 230 kV	70410	70048
	FSVCON13	Ft. St. Vrain 230 kV	Ft. St. Vrain 230/22 kV transformer	70410	70409
*= Not in benchmark cases					

Appendix B

Table B- 2 Minimum Load Stability Disturbance List

		Faulted End	Circuit Faulted	From Bus No	To Bus No
General Contingencies					
	GCON1	Comanche	Comanche - Midway 230 kV	70122	70286
	GCON2	Comanche	Comanche - Fuller 230 kV	70122	73477
	GCON3	Daniels Park	Daniels Park - Midway PS 230 kV	70139	70286
	GCON4	Midway PS	Midway PS - Daniels Park 230 kV	70286	70139
	GCON5	Lookout	Lookout - Cabin Creek 230 kV	70266	70072
	GCON6	Lookout	Lookout - West PS 230 kV	70266	70480
	GCON7	Cherokee	Cherokee - Lacombe 230 kV	70107	70324
	GCON8	Boone	Boone - Midway PS 230 kV	70061	70286
	GCON9	Boone	Boone - Lamar 230 kV	70061	70254
	GCON10	Boone	Boone - Comanche 230 kV	70061	70122
	GCON11	Lamar	Lamar - Colorado Green 230 kV	70254	70700
	GCON12	Lamar	Lamar - Lamar DC	70254	70801
	GCON13	Story	Story - LRS	73193	73108
	GCON14	LRS 345 kV	LRS 345/230 kV Transformer	73108	73107
	GCON15	LRS	LRS - Ault 345 kV	73107	73012
	GCON16	Ault	Ault - Craig 345 kV	73012	79014
	GCON17	Ault	Ault - Windsor 230 kV	73011	70474
	GCON18	Ault	Ault - Weld 230 kV	73011	73212
W009 Contingencies					
	PCON1	Pawnee	Pawnee - Ft. Lupton 230 kV	70311	70192
	PCON2	Pawnee	Pawnee - Quincy 230 kV	70311	70343
	PCON3	Pawnee	Pawnee - Story 230 kV	70311	73192
	PCON4	Pawnee	Pawnee - W009 230 kV	70311	70542
	PCON5	Pawnee 230 kV	Pawnee 230/22.1 kV Transformer	70311	70310
	PCON6	Pawnee	Pawnee - Daniels Park 230 kV	70311	70139
	PCON7	W009 230 kV	W009 230/34.5 kV transformer	70542	70815
	PCON8	No Fault	Drop Pawnee 1		
W022 Contingencies					
	RCON1	W022 Tap	W022 Tap - W022 230 kV	70545	70546
	RCON2	W022 Tap	W022 Tap - Green Valley 230 kV	70545	70048
	RCON3	W022 Tap	W022 Tap - RMEC 230 kV	70545	70590
	RCON4	W022 230 kV	W022 230/34.5 kV transformer	70546	70823
	RCON5	RMEC	RMEC - W022 Tap 230 kV	70590	70545
G025 Contingencies					
	SCON1	Spruce	Spruce - Picadilly 230 kV	70528	70530
	SCON2	Spruce	Spruce - Chambers 230 kV	70528	70539
	SCON3	Spruce	Spruce - Smoky Hill 230 kV	70528	70396
	SCON4	Spruce	Spruce - Sky Ranch 230 kV	70528	70392
	SCON5	Spruce	Spruce - Green Valley 230 kV	70528	70048
G029 Contingencies					
	FSVCON4	Ft. St. Vrain	Ft. St. Vrain - Ft. Lupton 230 kV	70410	70192
	FSVCON6	Ft. St. Vrain	Ft. St. Vrain - Isabelle 230 kV	70410	70544
	FSVCON7	Ft. St. Vrain	Ft. St. Vrain - Longs Peak 230 kV	70410	73116
	FSVCON8	Ft. St. Vrain	Ft. St. Vrain - Fordham 230 kV	70410	73562
	FSVCON9	Ft. St. Vrain	Ft. St. Vrain - Windsor 230 kV	70410	70474
	FSVCON10	Ft. St. Vrain	Ft. St. Vrain - Weld PS 230 kV	70410	70471
	FSVCON11	Ft. St. Vrain	Ft. St. Vrain - Valmont 230 kV	70410	70447
	FSVCON12	Ft. St. Vrain	Ft. St. Vrain - Green Valley 230 kV	70410	70048
Ridge Crest Contingencies					
	RCCON1	Peetz 115 kV	Peetz-Sterling 115 kV	73150	73191
	RCCON2	Peetz 115 kV	Peetz-Sidney 115 kV	73150	73179
Ponnequin Contingencies					
	QCON1	Ponnequin 115 kV	Ponnequin - Cheyenne 115 kV	73504	73043
	QCON2	Ponnequin 115 kV	Ponnequin - Rockport Tap 115 kV	73504	73172
Spring Canyon Contingencies					
	SPCCON1	Spring Canyon 230 kV	Spring Canyon - Sidney 230 kV	73579	73180
	SPCCON2	Spring Canyon 230 kV	Spring Canyon - N. Yuma 230 kV	73579	73143
*= No. of cases					49

Appendix C

Table C- 1 Peak Load Stability Results

	Meets Criteria? Y/N	Bus With Maximum Transient Volt Dev.	Maximum Transient Voltage Deviation-%	Short-Term[1] Post-Transient Voltage Deviation-%
General Contingencies				
GCON1	Y	WILOW CK	7.83%	0.02%
GCON2	Y	WILOW CK	7.78%	0.00%
GCON3	Y	PAWNEE 2	1.26%	0.07%
GCON4	Y	CLR 1 0.	1.37%	0.00%
GCON5	Y	CLR 1 0.	1.28%	0.01%
GCON6	Y	WESTPS 2	1.50%	1.19%
GCON7	Y	CLR 1 0.	1.47%	0.12%
GCON8	Y	LAMAR CO	4.68%	0.03%
GCON9	N	LAMAR CO		
GCON10	Y	LAMAR CO	3.71%	0.02%
GCON11	Y	LAMAR CO	8.75%	0.02%
GCON12	Y	CLR 1 0.	1.92%	0.82%
GCON13	Y	SPRNGCAN	2.18%	1.57%
GCON14	Y	LAR.RIVR	2.22%	1.52%
GCON15	Y	CLR 1 0.	10.66%	5.95%
GCON16	Y	CLR 1 0.	2.46%	0.61%
GCON17	Y	CLR 1 0.	2.13%	0.02%
GCON18	Y	CLR 1 0.	2.01%	0.04%
Pawnee Contingencies				
PCON1	Y	PAWNEE 2	1.37%	0.27%
PCON2	Y	CLR 1 0.	1.38%	0.62%
PCON3	Y	PAWNEE 2	1.24%	0.07%
PCON4	Y	CLR 1 0.	2.16%	0.74%
PCON5	Y	PAWNEE 2	1.52%	1.29%
PCON6	Y	QUINCY 2	1.45%	0.92%
PCON7	Y	CLR 1 0.	5.91%	0.00%
RMEC Contingencies				
RCON1	Y	CLR 1 0.	1.99%	1.03%
RCON2	Y	CLR 1 0.	0.42%	0.03%
RCON3	Y	CLR 1 0.	0.41%	0.05%
RCON4	Y	CLR 1 0.	0.55%	0.44%
RCON5	Y	CLR 1 0.	0.37%	0.04%
Spruce Contingencies				
SCON1	Y	CLR 1 0.	1.29%	0.05%
SCON2	Y	CLR 1 0.	1.29%	0.05%
SCON3	Y	CLR 1 0.	1.23%	0.11%
SCON4	Y	CLR 1 0.	1.27%	0.07%
SCON5	Y	CLR 1 0.	1.27%	0.07%
SCON6	Y	CLR 1 0.	2.02%	0.44%
SCON7	Y	CLR 1 0.	1.95%	0.41%
Ft St Vrain Contingencies				
FSVCON1	Y	CLR 1 0.	0.36%	0.09%
FSVCON2	N	ISABELLE	5.70%	5.51%
FSVCON3	Y	CLR 1 0.	1.00%	0.49%
FSVCON4	Y	CLR 1 0.	1.53%	0.20%
FSVCON5	Y	CLR 1 0.	1.70%	0.09%
FSVCON7	Y	CLR 1 0.	1.99%	0.17%
FSVCON8	Y	CLR 1 0.	1.75%	0.00%
FSVCON9	Y	CLR 1 0.	1.97%	0.11%
FSVCON10	Y	CLR 1 0.	2.01%	0.14%
FSVCON11	Y	CLR 1 0.	1.45%	0.24%
FSVCON12	Y	CLR 1 0.	1.65%	0.16%
FSVCON13	Y	CLR 1 0.	4.09%	1.48%

Note:

1. At 10 seconds.

Appendix D

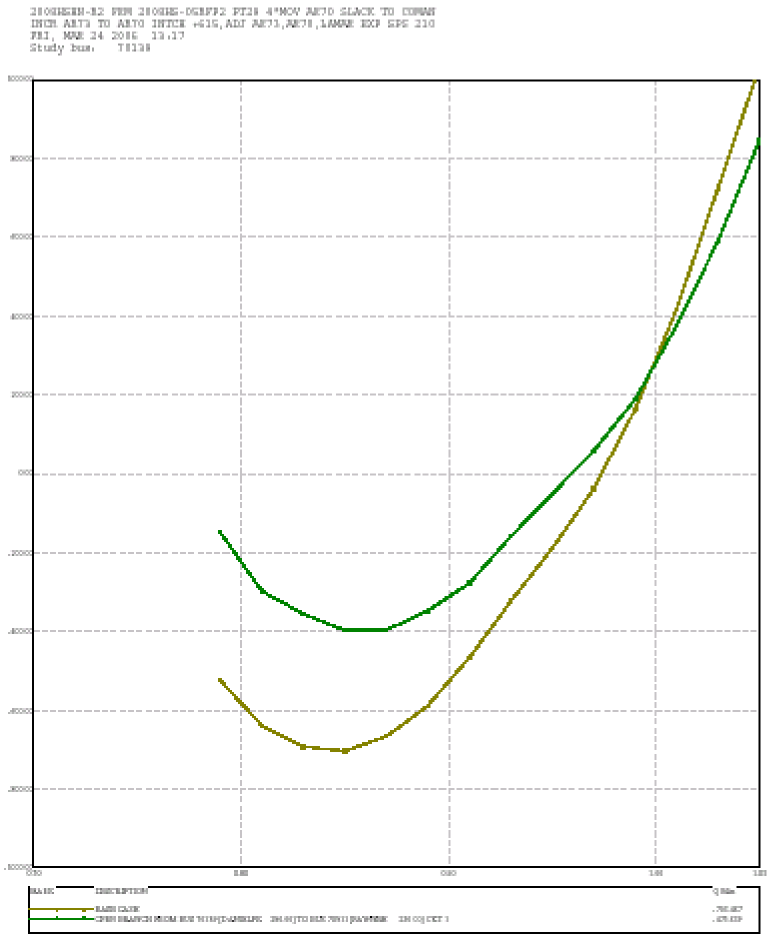


Figure D- 1 QV Results for Benchmark Case

Appendix D

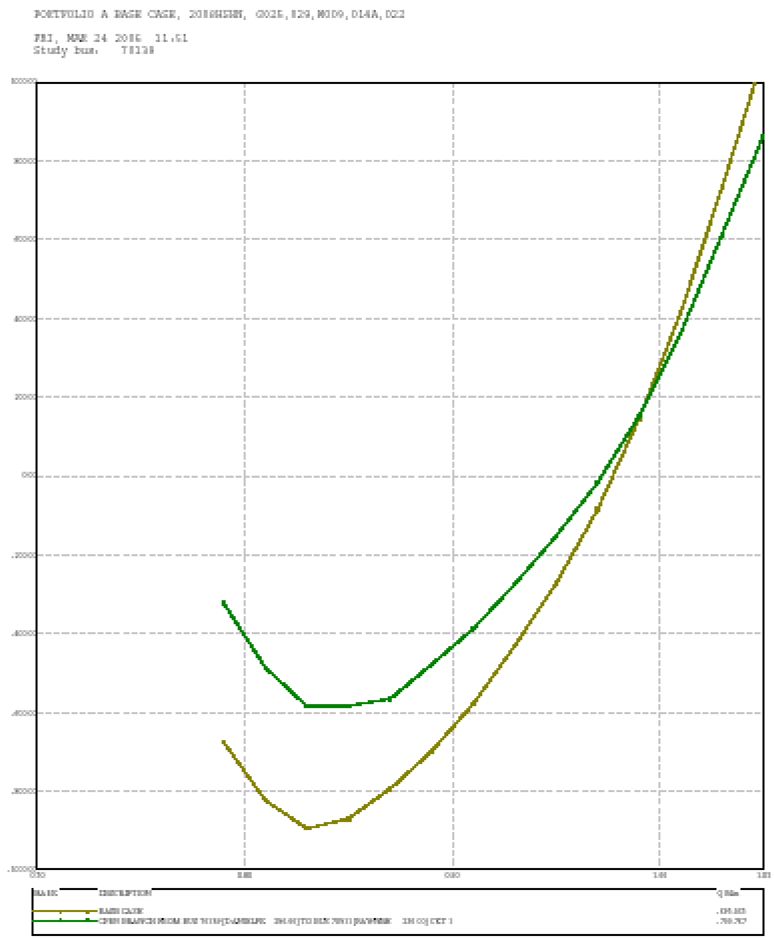


Figure D- 2 QV Results with Additional Wind Generation

Public Service Company of Colorado

Operating Procedures and Practices For Existing and Potential 2003 Least Cost Resource Plan Wind Generation

April 2006

Ponnequin
30 MW Wind Facility

Operating Procedures & Practices for PSCo

Summary:

Ponnequin is a 30 MW wind facility with a point of interconnection at Ponnequin 115 kV Switching Station on the Cheyenne to Ault 115 kV circuit, which is owned by WAPA. The generation is in the WAPA control area, and WAPA is responsible for providing transmission service to PSCo points of delivery.

1. Tot 3

This plant is connected to a TOT 3 element, but does not impact TTC or ATC.

2. Reliability

There is no history of reliability issues with the 115 kV circuit or any instability issues related to these wind generators.

3. Notification

PSCo operator and/or WAPA will notify the generator of any outages or restoration issues related to the 115 kV transmission line.

Ridge Crest
30 MW Wind Facility

Operating Procedures & Practices for PSCo

Summary:

Ridge Crest is a 30 MW wind generation facility with a point of interconnection at Peetz Switching Station, which is on the Sterling – Sidney 115 kV line. This generation is in the WAPA control area, and WAPA is responsible for providing transmission service from the facility to PSCo load delivery points.

1. 115 kV Configuration

When the 115 kV circuit from Sterling to Sidney (owned by WAPA) is tripped, the wind generation is removed, as the line is not sectionalized for a fault.

2. TOT 3

This plant is connected to a TOT 3 element, but does not impact TTC or ATC.

3. Reliability

Power flow and stability studies as well as operating experience have indicated that there is no reliability or stability issue with loss of the wind generator or the loss of the Sterling to Sidney 115 kV line.

Colorado Green
Existing: 162 MW Wind Facility; Potential: 75 MW in 2007

Operating Procedures & Practices for PSCo

Summary:

Colorado Green is a 162 MW wind generation facility that is interconnected at the Lamar 230 kV Switching Station via a 44-mile radial 230 kV circuit that is owned and operated by the Colorado Green facility. From the 2003 Least Cost Resource Plan, there is a potential 75 MW expansion of Colorado Green, which is projected to be in service in 2007. The entire facility will be operated as a single plant with a total installed capacity of 237 MW.

1. Boone—Lamar 230 kV line limit

The Boone to Lamar 230 kV line has a higher thermal rating (495 MVA) than the total potential wind generation (237 MW) plus HVDC import (210 MW). Contingency plans for the loss of this line include complete shutdown of the wind generation and the Lamar HVDC tie flow, accomplished through protective relaying. Rocky Mountain Reserve Group (RMRG) activation is required if Colorado Green and HVDC net inflow is 200 MW or greater when the Boone to Lamar 230 kV line (circuit 5337) trips.

In the event of the loss of Boone to Lamar 230 kV line, the Operations Control Center will notify the Colorado Green Wind Facility of the loss and the expected restoration times.

2. Lamar autotransformer

The 100 MVA autotransformer is protected from overload by the same protective relaying scheme that trips Colorado Green and the Lamar HVDC tie for the loss of the Boone to Lamar 230 kV line (circuit 5337).

3. Transmission Rights on Boone—Lamar

PSCo will redispatch the Lamar HVDC tie or secure transmission capacity so the generation from Colorado Green and the Lamar HVDC East to West transfer do not exceed PSCo transmission rights on the Boone to Lamar 230 kV line. PSCo transmission rights on the Boone - Lamar 230 kV line are 272 MVA or 55% of the line rating.

4. Reliability

There have been no reliability or instability issues associated with the wind generation or with an outage of the Boone to Lamar line.

Spring Canyon Energy
60 MW Wind Facility

Operating Procedures & Practices for PSCo

Summary:

Spring Canyon Energy is a 60 MW wind generation facility with a point of interconnection at the Spring Canyon 230 kV Switching Station, on the Sidney to North Yuma (N. Yuma) 230 kV line. This generation is in the WAPA control area. PSCo is a joint owner in the 230 kV line from Sidney to N. Yuma.

1. Spring Canyon—N. Yuma 230 kV line outage

For the loss of the Spring Canyon to N. Yuma 230 kV line, Spring Canyon wind generation automatically ramps to zero net power output within eighteen seconds, in order to prevent potential operating limit violations. The Spring Canyon wind facility is tripped offline through protective relaying ("watch dog relay") after eighteen seconds, if the net output has not been adequately reduced. As of April 2006, loss of Story – N. Yuma 230 kV line will require reduction of Spring Canyon generation unless additional transmission capacity is purchased.

Operations Control Center will notify the Wind Facility in the event of the loss of the Spring Canyon - N. Yuma 230 kV line, or the N. Yuma – Story 230 kV line.

2. Pawnee Station—Denver load center restriction

Potential overloads for N-1 conditions on the 230 kV lines from Pawnee Station into Denver Metro Area may require a reduction in power injected into Pawnee from all the generation sources including gas, coal and wind.

The Power Control and Dispatch group in Energy Supply will be given power limit guidance from the Operations group as needed when actual limits are approached based on the use of Real-Time Contingency Analysis (RTCA).

In the event of the loss of any line from Pawnee Station and its restoration the Operations Control Center will notify the Wind Facility.

3. TOT 3

This plant is connected to a TOT 3 element, but does not impact TTC or ATC.

4. Reliability

Power flow and stability studies as well as operating experience have indicated that there are no reliability or stability issue with loss of the wind generator or the loss of the 230 kV line from Sidney to N. Yuma.

Logan Wind
Potential 400 MW Wind Facility in 2007

Operating Procedures & Practices for PSCo

Summary:

Logan Wind is a potential wind project from the 2003 Least Cost Resource Plan. It is a 400 MW facility that would interconnect at the Pawnee 230 kV switching station via a 70-mile radial 230 kV line that would be owned and operated by the generation owner.

1. Pawnee Station—Denver load center restriction

Potential overloads for N-1 conditions on the 230 kV lines from Pawnee Station into Denver Metro Area may require a reduction in power injected into Pawnee from all the northeast area generation sources including gas, coal and wind.

The Power Control and Dispatch group in Energy Supply will be given power limit guidance from the Operations group as needed when actual limits are approached based on the use of Real-Time Contingency Analysis (RTCA).

2. Reliability

Power flow and stability studies have indicated that there are no reliability or stability issues with loss of the wind generator or the loss of the radial 230 kV line.

3. Future

A more detailed operating procedure will be developed as more operating details are know about the plant and we come closer to the commercial operation date.

Cedar Creek Wind
Potential 300 MW facility in 2007

Operating Procedures & Practices for PSCo

Summary:

Cedar Creek (CC) Wind is a potential wind project from the 2003 Least Cost Resource Plan. It is a 300 MW facility that would interconnect at a new Cedar Switching Station on one of the 230 kV lines (circuit 5279) between Rocky Mountain Energy Center (RMEC) and Green Valley Switching Station. The facility would connect to the Cedar Switching Station via a 50-mile radial 230 kV line that would be owned and operated by the generation owner.

1. RMEC / Cedar – Green Valley Flow Restriction

With the prior outage of either the RMEC - Green Valley 230 kV line (5271) or the CC to Green Valley 230 kV line (5279), subsequent loss of the other line will sever the connection of RMEC and CC to Green Valley and cause the generation to be tripped at both RMEC and CC. Therefore, for either of these prior outages, Operations may limit the combined generation output of the RMEC and CC facilities to 565 MW. This restriction is imposed because loss of the remaining line would require Rocky Mountain Reserve Group (RMRG) activation if generation totals 200 MW or greater, which cannot exceed the RMRG's largest hazard of 565 MW.

The Power Control and Dispatch group in Energy Supply will be given power limit guidance from the Operations group as needed when actual limits are approached based on the use of Real-Time Contingency Analysis (RTCA).

2. Reliability

Power flow and stability studies as have indicated that there are no reliability or stability issue with loss of the wind generator or the loss of the neighboring 230 kV line.

3. Future

A more detailed operating procedure will be developed as more operating details are know about the plant and we come closer to the commercial operation date.